San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

DOCKET
06-AFC-5
DATE JUL 1 3 2007
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JUL 13 2007

James Reede
Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: Notice of Preliminary Determination of Compliance (PDOC)
Project Number: C1062518 – Panoche Energy Center LLC (06-AFC-5)

Dear Mr. Reede:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 400 MW simple cycle, peaking power plant, located at SW/4 Section 5, T15S, R13E on W. Panoche Road in Firebaugh, CA. This letter serves as our notification of final action and enclosed is your copy of the FDOC.

Notice of the District's preliminary decision was published on May 9, 2007. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments G, H and I of the enclosed FDOC package.

The changes made to the Preliminary Determination of Compliance (PDOC) were in direct response to comments received from the oversight agencies, the applicant, and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not significantly increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Arnaud Marjollet of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:st

Enclosures

Fresno Bee

NOTICE OF FINAL DETERMINATION OF COMPLIANCE

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District has issued a Final Determination of Compliance to Panoche Energy Center LLC for the installation of a nominal 400 MW simple cycle, peaking power plant, located at SW/4 Section 5, T15S, R13E on W. Panoche Road in Firebaugh, CA.

All comments received following the District's preliminary decision on this project were considered. Changes were made to the DOC in direct response to comments received from the oversight agencies, the applicant, and other interested parties. The changes made were minor and did not significantly increase permitted emission levels or trigger additional public notification requirements.

The application review for project C-1062518 is available for public inspection at the **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

San Joaquin Valley Air Pollution Control District

Invoice Detail

Facility ID: C7220

PANOCHE ENERGY CENTER LLC
W PANOCHE RD
FIREBAUGH, CA

Invoice Nbr: C113796
Invoice Date: 7/13/2007
Page: 1

Application Filing Fees

Project Nbr	Permit Number	Description	Application Fee
C1062518	C-7220-1-0	100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST	$ 60.00
C1062518	C-7220-2-0	100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST	$ 60.00
C1062518	C-7220-3-0	100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #3 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST	$ 60.00
C1062518	C-7220-4-0	100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #4 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST	$ 60.00
C1062518	C-7220-5-0	160 BHP JOHN DEERE MODEL 6068T, OR EQUIVALENT, TIER 2 CERTIFIED DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIREWATER PUMP	$ 60.00
C1062518	C-7220-6-0	27,600 GPM COOLING TOWER WITH 5 CELLS AND DRIFT ELIMINATOR	$ 60.00
		Total Application Filing Fees:	**$ 360.00**

Engineering Time Fees

Project Nbr	Quantity	Rate	Description	Fees
C1062518	120.5 hours	$ 86.00 /h	Standard Engineering Time	$ 10,363.00
			Less Credit For Application Filing Fees	($ 360.00)
			Standard Engineering Time SubTotal	$ 10,003.00
			Total Engineering Time Fees:	**$ 10,003.00**

FINAL DETERMINATION OF COMPLIANCE EVALUATION

Panoche Energy Center Project
California Energy Commission
Application for Certification Docket #: 06-AFC-5

Facility Name:	Panoche Energy Center LLC
Mailing Address:	63 Kendrick St Needham, MA 02494
Contact Name:	Gary R. Chandler, President
Telephone:	(801) 253-1278
Fax:	(801) 910-3427
Alternate Contact:	John Lague
Telephone:	(619) 294-9400
Fax:	(619) 293-7920
E-Mail:	John_Lague@urscorp.com
Engineer:	Stanley Tom, Senior Air Quality Engineer
Lead Engineer:	Joven Refuerzo, Supervising Air Quality Engineer
Date:	April 11, 2007
Project #:	C-1062518
Application #'s:	C-7220-1-0, C-7220-2-0, C-7220-3-0, C-7220-4-0, C-7220-5-0, and C-72220-6-0
Submitted:	August 10, 2006

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I. Proposal

Panoche Energy Center LLC (PEC) is seeking approval from the San Joaquin Valley Air Pollution Control District for the installation of an electrical power generation facility. Panoche will be a simple-cycle power generation facility consisting of four General Electric LMS100 natural gas-fired combustion turbine generators (CTGs), each equipped with water injection to the combustors, a selective catalytic reduction (SCR) system with 19 percent aqueous ammonia injection, and an oxidation catalyst. The total net generating capacity will be approximately 400 megawatts (MW).

PEC is proposing to install a 160 bhp diesel-fired emergency internal combustion (IC) engine powering a firewater pump and a 27,600 gallon per minute cooling tower.

PEC is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

The California Energy Commission (CEC) is the lead agency for this project for the requirements of the California Environmental Quality Act (CEQA).

Additionally, PEC is subject to Prevention of Significant Deterioration requirements by EPA Region IX.

II. Applicable Rules

Rule 1080 Stack Monitoring (12/17/92)
Rule 1081 Source Sampling (12/16/93)
Rule 1100 Equipment Breakdown (12/17/92)
Rule 2010 Permits Required (12/17/92)
Rule 2201 New and Modified Stationary Source Review Rule (9/21/06)
Rule 2520 Federally Mandated Operating Permits (6/21/01)
Rule 2540 Acid Rain Program (11/13/97)
Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)
Rule 4001 New Source Performance Standards (4/14/99)
Subpart GG - Standards of Performance for Stationary Gas Turbines
NSPS Subpart KKKK - Standards of Performance for Stationary Gas Turbines
Rule 4002 National Emissions Standards for Hazardous Air Pollutants (5/18/00)
Rule 4101 Visible Emissions (2/17/05)
Rule 4102 Nuisance (12/17/92)
Rule 4201 Particulate Matter Concentration (12/17/92)
Rule 4202 Particulate Matter Emission Rate (12/17/92)
Rule 4301 Fuel Burning Equipment (12/17/92)
Rule 4701 Stationary Internal Combustion Engines – Phase 1 (8/21/03)
Rule 4702 Stationary Internal Combustion Engines – Phase 2 (1/18/07)
Rule 4703 Stationary Gas Turbines (8/17/06)

Rule 4801 Sulfur Compounds (12/17/92)
Rule 7012 Hexavalent Chromium - Cooling Towers (12/17/92)
Rule 8011 General Requirements (8/19/04)
Rule 8021 Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04)
Rule 8031 Bulk Materials (8/19/04)
Rule 8051 Open Areas (8/19/04)
Rule 8061 Paved and Unpaved Roads (8/19/04)
Rule 8071 Unpaved Vehicle/Equipment Traffic Areas (9/16/04)
California Environmental Quality Act (CEQA)
CH&SC 41700 Health Risk Assessment
CH&SC 42301.6 School Notice
CH&SC 44300 (Air Toxic "Hot Spots")
Title 13 California Code of Regulations (CCR), Section 2423 – Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment
Title 17 CCR, Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

III. Project Location

The site is located approximately 50 miles west of City of Fresno and approximately 2 miles east of Interstate 5, in Fresno County. The equipment will be located at the SW/4 of Section 5, Township 15S, Range 13E. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

Combustion Turbine Generators

The GE LMS100 is an inter-cooled gas turbine system developed especially for the power generation industry utilizing heavy-duty gas turbine and aero-derivative gas turbine technology. The LMS100 produces approximately 100 MW at an efficiency that is 10 percent higher than other commercial simple-cycle turbines. The LMS100 is specifically designed for cyclic applications providing flexible power and 10 minute starts.

Electricity generated by PEC will be delivered to the existing Pacific Gas and Electric (PG&E) electrical transmission system at the adjacent Panoche Substation. Interconnection at this substation will minimize impacts to the PG&E transmission system while providing efficient peaking power for use during peak demand.

Auxiliary equipment will include inlet air filters with evaporative coolers, turbine compressor section inter-cooler, mechanical draft cooling tower, circulating water pumps, water treatment equipment, natural gas compressors, generator step-up and auxiliary transformers, and water storage tanks.

A CTGs power output is defined by its capacity factor. The capacity factor average the engine's output and divides that by the engine's rated output for a typical day. Each CTG will generate 100 MW net at summer design ambient conditions. The project will have an annual capacity factor of approximately 57 percent, depending on dispatch to meet annual demand.

Electric power generated at the PEC facility will be sold to PG&E under a 20-year power purchase agreement (PPA) between PEC and PG&E. Design of the plant and equipment selection is based on requirements in the PPA.

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record fuel gas flow rate, NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG. This system will generate reports of emission data in accordance with permit requirements and will send alarm signals to the plant's control system when emissions approach or exceed pre-selected limits.

Diesel-fired Emergency Engine

The emergency engine powers a firewater pump. Other than emergency operation, the engine may be operated up to 52 hours per year for maintenance and testing purposes.

Cooling Tower

One mechanical-draft evaporative cooling tower will be used to provide cooling water for the steam turbine surface condenser and other cooling loads. The cooling tower will consist of 5 cells and have a design water flow rate of 27,600 gallons per minute (gpm). The cooling tower will be equipped with a high efficiency mist eliminator to minimize cooling tower drift and the resultant PM10 emissions. The PM10 emissions are due to total dissolved solids (TDS) in the cooling water. No chromium containing compounds will be added to the cooling water.

V. Equipment Listing

C-7220-1-0: 100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST

C-7220-2-0: 100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST

C-7220-3-0: 100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #3 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST

C-7220-4-0: 100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #4 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST

C-7220-5-0: 160 BHP JOHN DEERE MODEL 6068T, OR EQUIVALENT, TIER 2 CERTIFIED DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIREWATER PUMP

C-7220-6-0: 27,600 GPM COOLING TOWER WITH 5 CELLS AND DRIFT ELIMINATOR

VI. Emission Control Technology Evaluation

C-7220-1-0 through '4-0

The combustion gases exit the turbine at approximately 700 degrees F and then pass through the hot SCR system for NOx emission control and an oxidizing catalyst for control of CO and VOC emissions. The SCR system is used in conjunction with ammonia injection for the control of NOx emissions. A 19 percent aqueous ammonia solution is injected into the CTG exhaust gas stream that passes over a catalyst bed that reduces the oxides of nitrogen to inert nitrogen. The SCR equipment includes a reactor chamber, catalyst modules, ammonia storage system, ammonia vaporization and injection system, and monitoring equipment and sensors. The ammonia unloading area will consist of a curbed concrete pad and containment vault. After passing through the SCR system, the exhaust gases exit the attached stack.

Emissions from natural gas-fired turbines include NO_X, CO, VOC, PM_{10}, and SO_X.

NO_X is the major pollutant of concern when combusting natural gas. Virtually all gas turbine NO_X emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule. There are two mechanisms by which NO_X is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_X and prompt NO_X), and 2) the conversion of nitrogen chemically bound in the fuel (fuel NO_X).

Thermal NO_X is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NO_X.

Fuel NO_X is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N_2 in some natural gas, does not contribute significantly to fuel NO_X formation. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NO_X, fuel NO_X is not currently a major contributor to overall NO_X emissions from stationary gas turbines firing natural gas.

The level of NO_X formation in a gas turbine, and hence the NO_X emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_X generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

Selective Catalytic Reduction systems selectively reduce NO_X emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. SCR is capable of over 90 percent NO_X reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 °F. Exhaust gas temperatures greater than the upper limit (750 °F) will cause NO_X and NH_3 to pass through the catalyst unreacted. Ammonia slip will be limited to 10.0 ppmvd @ 15% O_2.

An oxidation catalyst utilizes a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide (CO_2). This type of control device is also somewhat effective for controlling VOC emissions by a similar chemical reaction to that of carbon monoxide.

C-7220-5-0

The engine is equipped with:
[X] Turbocharger
[X] Very Low (0.0015%) sulfur diesel

The emission control devices/technologies and their effect on diesel engine emissions detailed below are from *Non-catalytic NO_X Control of Stationary Diesel Engines*, by Don Koeberlein, CARB.

The turbocharger reduces the NO_X emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

The use of very low-sulfur diesel fuel (0.0015% by weight sulfur maximum) reduces SO_X emissions by over 99% from standard diesel fuel.

C-7220-6-0

The lube oil coalescer will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

The cooling towers are a source of PM10 emissions. PM10 emissions are due to the total dissolved solids (TDS), mostly salts, in the cooling water. In the cooling process, some of the cooling water (and TDS) is carried out. This is referred to as drift. Some portion of the drift dries in the air before settling to ground, and its TDS content can thereby become airborne PM. The applicant has conservatively assumed that all drift will remain suspended in the air and will dry to PM10. This approach overstates PM10 emissions.

Cooling water drift is controlled by using drift eliminators in each of the cooling tower cells. These drift eliminators act as a coalescer for the evolved cooling water to collect on and drop back into the process stream. The proposed drift eliminators have a drift rate of 0.0005%, i.e. 0.0005% of the cooling water circulated is emitted.

VII. General Calculations

A. Assumptions

C-7220-1-0 through '4-0

- Each CTG will generate approximately 100 MW under most ambient conditions. The CTGs are expected to operate no more than 5,000 hours per year (each CTG), with an expected plant capacity factor of 57 percent.
- CTG Power Output = 103 MW at the generator terminals
- CTG Fuel Flow = 878,906 scf/hr, higher heating value (HHV)
- CTG Heat Rate = 7815 Btu/kilowatt hour (kWh), HHV
- CTG Heat Input Rating = 909.7 MMBtu/hr
- Maximum daily emissions for each CTG are estimated assuming three startup events (30 min per event), three shutdown events (10.5 min per event), and the remaining time operating at full load.
- Maximum annual emissions for each CTG are estimated assuming 365 startup events (30 min per event), 365 shutdown events (10.5 min per event), and the remaining hours operating at full load (5,000 total hours/year).
- Commissioning emissions will count towards the annual emission limit for each CTG.
- Maximum quarterly hours of operation = 1,100 hr (1^{st} Qtr), 1,100 hr (2^{nd} Qtr), 1,600 hr (3^{rd} Qtr), 1,200 hr (4^{th} Qtr) (per applicant)

C-7220-5-0

Emergency operating schedule:	24 hours/day
Non-emergency operating schedule:	up to 52 hours/year
Density of diesel fuel:	7.1 lb/gal
EPA F-factor (adjusted to 60 °F):	9,051 dscf/MMBtu
Fuel heating value:	137,000 Btu/gal
BHP to Btu/hr conversion:	2,542.5 Btu/bhp-hr
Thermal efficiency of engine:	commonly ≈ 35%
PM_{10} fraction of diesel exhaust:	0.96 (CARB, 1988)

- The applicant has only supplied an emissions factor for NO_X and VOC emissions combined. Therefore the District will use data from the EPA document *"Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling – Compressions Ignition"*, dated November 2002, as presented in the following table to estimate NO_X and VOC emissions (District assumption).

Tier 2 and Tier 3 Diesel-Fired IC Engines NO_X and VOC Estimated Emissions						
Horsepower Range (bhp)	Combined Standard, (NO_X + VOC) (g/bhp-hr)		Estimated NO_X Emissions (g/bhp-hr)		Estimated VOC Emissions (g/bhp-hr)	
	Tier 2	Tier 3	Tier 2	Tier 3	Tier 2	Tier 3
≥50 to < 100	5.6	3.5	5.2	3.3	0.4	0.2
≥100 to < 175	4.9	3.0	4.5	2.8	0.4	0.2
≥175 to < 300	4.9	3.0	4.5	2.8	0.4	0.2
≥300 to < 600	4.8	3.0	4.5	2.8	0.3	0.2
≥600 to < 750	4.8	3.0	4.5	2.8	0.3	0.2
≥750	4.8	N/A	4.5	N/A	0.3	N/A

For this application for a 160 bhp Tier 2 certified IC engine the applicant supplied NO_X + VOC emissions factor is 4.90 g/bhp-hr. Therefore, the NO_X and VOC emissions factors for this engine are calculated as follows:

NO_X (g/bhp-hr) = (NO_X + VOC) (g/bhp-hr) x (4.5 g/bhp-hr ÷ 4.9 g/bhp-hr)
NO_X g/bhp-hr = 4.90 g/bhp-hr x (4.5 g/bhp-hr ÷ 4.9 g/bhp-hr)
NO_X = 4.5 g/bhp-hr

VOC (g/bhp-hr) = (NO_X + VOC) (g/bhp-hr) x (0.4 g/bhp-hr ÷ 4.9 g/bhp-hr)
VOC g/bhp-hr = 4.90 g/bhp-hr x (0.4 g/bhp-hr ÷ 4.9 g/bhp-hr)
VOC = 0.4 g/bhp-hr

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- PM_{10} is the only criteria pollutant emitted by the cooling tower
- Density of water = 8.34 lb/gal
- Cooling tower drift eliminator has a drift rate of 0.0005% (proposed by the applicant)
- TDS concentration shall not exceed 14.19 lb/1000 gallons (proposed by the applicant)
- Circulating water flow rate = 27,600 gallons per minute (proposed by the applicant)
- Cycles of concentration = 3 (proposed by the applicant)

B. Emission Factors

C-7220-1-0 through '4-0

After commissioning of the CTG units, the emissions from the stack for each CTG at full load conditions (63 °F ambient temperature) are as follows:

2.5 ppmvd NOx @ 15% O2
2.51 lb/hr SOx (based on 1.0 gr-S/100 scf)
6.0 lb/hr PM10

6.0 ppmvd CO @ 15% O2
2.0 ppmvd VOC @ 15% O2
10.0 ppmvd NH3 @ 15% O2

The maximum air contaminant mass emission rates (lb/hr), concentrations (ppmvd @ 15% O_2), and startup, shutdown, and commissioning emissions rates per manufacturer's estimate for each of the proposed CTGs are summarized below:

Normal Emission Rates and Concentrations (@ 100% Load & 63 °F)						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	8.03	11.81	2.67*	6.00	2.51	11.90
ppmvd @ 15% O_2 limits	2.5	6.0	2.0	--	--	10.0

* Emissions are highest at 100% load and 63 F ambient temperature.

1.0 gr-S/100 scf x 878,906 scf/hr x lb/7000 gr x 64 lb SO2/32 lb S = 2.51 lb-SOx/hr

Startup Emissions (10-minute duration)					
	NO_X (lb/event)	CO (lb/event)	VOC (lb/event)	PM_{10} (lb/event)	SO_X (lb/event)
Mass Emission Rate (per turbine)	5.00	14.00	3.00	1.00	0.42

Warmup Emissions (20-minute duration)					
	NO_X (lb/event)	CO (lb/event)	VOC (lb/event)	PM_{10} (lb/event)	SO_X (lb/event)
Mass Emission Rate (per turbine)	17.20	39.30	0.80	2.00	0.84

Total Startup Emissions (Startup + Warmup 30-minute duration)					
	NO_X (lb/event)	CO (lb/event)	VOC (lb/event)	PM_{10} (lb/event)	SO_X (lb/event)
Mass Emission Rate (per turbine)	22.20	53.30	3.80	3.00	1.26

Worst Case Startup Emissions (1-hour duration)*					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
Mass Emission Rate (per turbine)	44.40	106.60	7.60	6.00	2.51

* Pursuant to the turbine vendor, "A start-up event is estimated to be completed in 30 minutes; however, for simplification the emissions for a start-up event are calculated as hourly emissions with the 30 minute start-up emissions for a duration of 1 hour."

Shutdown Emissions (10.5-minute duration)					
	NO_X (lb/event)	CO (lb/event)	VOC (lb/event)	PM_{10} (lb/event)	SO_X (lb/event)
Mass Emission Rate (per turbine)	6.00	47.00	3.00	1.05	0.44

Worst Case Shutdown Emissions (1-hour duration)*					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
Mass Emission Rate (per turbine)	34.29	268.57	17.14	6.00	2.51

* Pursuant to the turbine vendor, "A shutdown event is estimated to be completed in 10.5 minutes; however, for simplification the emissions for a shutdown event are calculated as hourly emissions with the 10.5 minute shutdown emissions for a duration of 1 hour."

Commissioning Emissions (Total)						
	Hours	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)	SO_X (lb)
First Fire	28	1371.00	800.00	17.00	168.00	N/A
Controlled Break-in	20	1236.00	721.00	15.00	120.00	N/A
Dynamic AVR	24	4488.00	4553.00	98.00	144.00	N/A
Base Load AVR	16	1274.00	4956.00	106.00	96.00	N/A
SCR Commissioning	24	849.00	215.00	43.00	144.00	N/A
Full Load Testing	24	191.00	266.00	53.00	144.00	N/A
Total Hours	136					

Commissioning Emissions (Maximum Hourly)					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
First Fire	48.96	28.57	0.61	6.00	N/A
Controlled Break-in	61.80	36.05	0.75	6.00	N/A
Dynamic AVR	187.00	189.71	4.08	6.00	N/A
Base Load AVR	79.63	309.75	6.63	6.00	N/A
SCR Commissioning	35.38	8.96	1.79	6.00	N/A
Full Load Testing	7.96	11.08	2.21	6.00	N/A

C-7220-5-0

Emission Factors		
Pollutant	Emission Factor (g/bhp-hr)	Source
NO_X	4.5	Engine Manufacturer
SO_X	0.0051	Mass Balance Equation Below
PM_{10}	0.15	Engine Manufacturer
CO	0.6	Engine Manufacturer
VOC	0.4	Engine Manufacturer

$$\frac{0.000015\,\text{lb}-\text{S}}{\text{lb}-\text{fuel}} \times \frac{7.1\,\text{lb}-\text{fuel}}{\text{gallon}} \times \frac{2\,\text{lb}-\text{SO2}}{\text{lb}-\text{S}} \times \frac{1\,\text{gal}}{137{,}000\,\text{Btu}} \times \frac{1\,\text{bhp input}}{0.35\,\text{bhp output}} \times \frac{2{,}542.5\,\text{Btu}}{\text{bhp}-\text{hr}} \times \frac{453.6\,\text{g}}{\text{lb}}$$

$$= 0.0051\,\frac{\text{g}-\text{SOx}}{\text{bhp}-\text{hr}}$$

C-7220-6-0

The PM_{10} emissions from the cooling tower can be quantified using the drift of the circulating water flow rate, 0.0005%, the concentration of total dissolved solids in the water, 1,700 mg/L (14.19 lb/1000 gal).

Drift Rate = 0.0005%
TDS = 1700 mg/L (14.19 lb/1000 gal)

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since the emission units in this project are new, PE1 = 0 for all criteria pollutants.

2. Post Project Potential to Emit (PE2)

The potential to emit for each CTG is calculated as follows, and summarized in the table below:

C-7220-1-0 through '4-0

a. Maximum Hourly PE2

The maximum hourly potential to emit for NO_X from each CTG will occur when the unit is operating under startup mode. The maximum hourly PE for each turbine operating is when it is starting up. The maximum hourly emissions for each turbine is summarized in the table below:

Maximum Startup Emissions (1-hour duration)					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
Mass Emission Rate (per turbine)	44.40	106.60	7.60	6.00	2.51

Maximum Shutdown Emissions (1-hour duration)					
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)
Mass Emission Rate (per turbine)	34.29	268.57	17.14	6.00	2.51

Maximum Normal Emissions (@ 100% Load & 63 °F)						
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	SO_X (lb/hr)	NH_3 (lb/hr)
Mass Emission Rates (per turbine)	8.03	11.81	2.67	6.00	2.51	11.90
ppmvd @ 15% O_2 limits	2.5	6.0	2.0	--	--	10.0

b. Maximum Daily PE2

The maximum daily emissions occur when each CTG operates with 3 startups, 3 shutdowns, and the remainder at 100% load (@ 63 °F). The results for each turbine are summarized in the table below:

Maximum Daily Post Project Potential to Emit (PE2)				
	Startup Emissions Rate (lb/day)	Shutdown Emissions Rate (lb/day)	Emissions Rate @ 100% Load (lb/day)	Daily Emissions Limitation (lb/day) (per CTG)
Formula	lb/hr x 3 events/day x 30 min/event	lb/hr x 3 events/day x 10.5 min/event	lb/hr x (24 hour/day – 3 events/day x 30 min/event – 3 events/day x 10.5 min/event)	Startup + Shutdown + 100% Load
NO_X	44.40 x 3 x 30 min = 66.6	34.29 x 3 x 10.5 min = 18.0	8.03 x (24 – 3 x 30 min – 3 x 10.5 min) = 176.5	66.6 + 18.0 + 176.5 = 261.1
SO_X	N/A	N/A	2.51 x 24 = 60.2	60.2
PM_{10}	6.00 x 3 x 30 min = 9.0	6.00 x 3 x 10.5 min = 3.2	6.00 x (24 – 3 x 30 min – 3 x 10.5 min) = 131.9	9.0 + 3.2 + 131.9 = 144.1
CO	106.60 x 3 x 30 min = 159.9	268.57 x 3 x 10.5 min = 141.0	11.81 x (24 – 3 x 30 min – 3 x 10.5 min) = 259.5	159.9 + 141.0 + 259.5 = 560.4
VOC	7.60 x 3 x 30 min = 11.4	17.14 x 3 x 10.5 min = 9.0	2.67 x (24 – 3 x 30 min – 3 x 10.5 min) = 58.7	11.4 + 9.0 + 58.7 = 79.1
NH_3	N/A	N/A	11.90 x 24 = 285.6	285.6

c. Maximum Annual PE2

The maximum annual emissions occur when each CTG operates for 5,000 hours per year with 365 startups, 365 shutdowns, and the remainder at 100% load (@ 63 °F). The results for each turbine are summarized in the table below:

Maximum Annual Post Project Potential to Emit (PE2)				
	Startup Emissions Rate (lb/year)	Shutdown Emissions Rate (lb/year)	Emissions Rate @ 100% Load (lb/year)	Annual Emissions Limitation (lb/year) (per CTG)
Formula	lb/hr x 365 events/yr x 30 min/event	lb/hr x 365 events/yr x 10.5 min/event	lb/hr x (5000 hour/yr – 365 events/yr x 30 min/event – 365 events/yr x 10.5 min/event)	Startup + Shutdown + 100% Load
NO_X	44.40 x 365 x 30 min = 8,103	34.29 x 365 x 10.5 min = 2,190	8.03 x (5000 – 365 x 30 min – 365 x 10.5 min) = 38,172	8,103 + 2,190 + 38,172 = 48,465
SO_X	N/A	N/A	2.51 x 5000 = 12,550	12,550
PM_{10}	6.00 x 365 x 30 min = 1,095	6.00 x 365 x 10.5 min = 383	6.00 x (5000 – 365 x 30 min – 365 x 10.5 min) = 28,522	1,095 + 383 + 28,522 = 30,000
CO	106.60 x 365 x 30 min = 19,455	268.57 x 365 x 10.5 min = 17,155	11.81 x (5000 – 365 x 30 min – 365 x 10.5 min) = 56,140	19455 + 17155 + 56140 = 92,750
VOC	7.60 x 365 x 30 min = 1,387	17.14 x 365 x 10.5 min = 1,095	2.67 x (5000 – 365 x 30 min – 365 x 10.5 min) = 12,692	1,387 + 1,095 + 12,692 = 15,174
NH_3	N/A	N/A	11.90 x 5000 = 59,500	59,500

d. Summary of PE2

The hourly, daily, and annual PE2 for each turbine is summarized in the table below:

Post Project Potential to Emit (PE2) Summary (Each of C-7220-1-0, '2-0, '3-0, '4-0)		
	Daily Emissions (lb/day)	Annual Emissions (lb/year)
NO_X	261.1	48,465
SO_X	60.2	12,550
PM_{10}	144.0	30,000
CO	560.4	92,750
VOC	79.1	15,174
NH_3	285.6	59,500

C-7220-5-0

The daily and annual PE are calculated as follows:

Daily Post Project Emissions					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Daily Hours of Operation (hrs/day)	Conversion (g/lb)	PE2 Total (lb/day)
NO_X	4.5	160	24	453.6	38.1
SO_X	0.0051	160	24	453.6	0.0
PM_{10}	0.15	160	24	453.6	1.3
CO	0.6	160	24	453.6	5.1
VOC	0.4	160	24	453.6	3.4

Annual Post Project Emissions					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Annual Hours of Operation (hrs/yr)	Conversion (g/lb)	PE2 Total (lb/yr)
NO_X	4.5	160	52	453.6	83
SO_X	0.0051	160	52	453.6	0
PM_{10}	0.15	160	52	453.6	3
CO	0.6	160	52	453.6	11
VOC	0.4	160	52	453.6	7

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The applicant has proposed that the maximum water flowrate through the cooling tower is 27,600 gallons per minute. Therefore, the PM_{10} emissions from the cooling tower can be estimated using the emission factor listed above and the water flowrate.

Daily PM_{10} PE = Drift rate x TDS (lb/gallon) x water throughput (gal/min) x 60 min/hr x 24 hr/day
Daily PM_{10} PE = 0.000005 x 14.19 lb/1000 gallon x 27,600 gal/min x 60 min/hr x 24 hr/day
= 2.8 lb/day/cycle

There are three cycles of concentration for the cooling tower.

Daily PM_{10} PE = 2.8 lb/day/cycle x 3 cycles
= 8.4 lb/day

Daily PM_{10} PE = 8.4 lb/day

Annual PM_{10} PE = 0.000005 x 14.19 lb/1000 gallon x 27,600 gal/min x 60 min/hr x 5000 hr/yr x 3 cycles
= 1,762 lb/yr

Annual PM_{10} PE = 1,762 lb/yr

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-Project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 will be equal to zero.

4. Post Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Post Project Stationary Source Potential to Emit [SSPE2] (lb/year)					
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC
C-7220-1-0	48,465	12,550	30,000	92,750	15,174
C-7220-2-0	48,465	12,550	30,000	92,750	15,174
C-7220-3-0	48,465	12,550	30,000	92,750	15,174
C-7220-4-0	48,465	12,550	30,000	92,750	15,174
C-7220-5-0	83	0	3	11	7
C-7220-6-0	0	0	1,762	0	0
Post Project SSPE (SSPE2)	193,943	50,200	121,765	371,011	60,703

5. Major Source Determination

Pursuant to Section 3.24 of District Rule 2201, a Major Source is a stationary source with post-project emissions or a Post Project Stationary Source Potential to Emit (SSPE2), equal to or exceeding one or more of the following threshold values. However, Section 3.24.2 states, "for the purposes of determining major source status, the SSPE2 shall not include the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site."

Major Source Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
Pre-Project SSPE (SSPE1)	0	0	0	0	0
Post Project SSPE (SSPE2)	193,943	50,200	121,765	371,011	60,703
Major Source Threshold	50,000	140,000	140,000	200,000	50,000
Major Source?	Yes	No	No	Yes	Yes

As seen in the table above, the facility is a new Major Source for NOx, CO, and VOC as a result of this project.

6. Baseline Emissions (BE)

BE = Pre-project Potential to Emit for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to Section 3.22

Since these are new emission units, BE = PE1 = 0 for all criteria pollutants.

7. Major Modification

Major Modification is defined in 40 CFR Part 51.165 as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.*"

As discussed in Section VII.C.5 above, the facility is a new Major Source for NOx, CO, and VOC as a result of this project; therefore the project is not a Major Modification.

8. Federal Major Modification

As shown above, this project does not constitute a Major Modification. Therefore, in accordance with District Rule 2201, Section 3.17, this project does not constitute a Federal Major Modification and no further discussion is required.

VIII. Compliance

Rule 1080 Stack Monitoring

This Rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for record keeping, reporting, and notification. The facility will be equipped with operational CEMs for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

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Proposed Rule 1080 Conditions:

- The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]
- Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]
- Results of the CEM system shall be averaged over a one hour period for NOx emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]
- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]
- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703 and 40 CFR 60.4335(b)(1)]
- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]
- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet

equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]
- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]
- The owner/operator shall perform a relative accuracy test audit (RATA) for the NOx, CO, and O2 CEMs as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]
- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing; evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201, and 4703 and 40 CFR 60.8(d)]
- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; a negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]
- The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

Rule 1081 Source Sampling

This Rule requires adequate and safe facilities for using in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection. The requirements of this Rule will be included in the operating permit. Compliance with this Rule is anticipated.

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Proposed Rule 1081 Conditions:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]
- Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-7220-1, C-7220-2, C-7220-3, or C-7220-4) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rule 1081]
- Source testing to measure the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 120 days after initial operation and at least once every twelve months thereafter. [District Rules 1081 and 4703 and 40 CFR 60.4400(a)]
- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
- The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia – EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

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Proposed Rule 1081 Condition:

- Compliance with PM10 emission limit shall be determined by a blowdown water sample analysis conducted by an independent laboratory within 60 days of initial operation and quarterly thereafter. [District Rule 1081]

Rule 1100 Equipment Breakdown

This Rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified.

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1100 Conditions:

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]
- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

Rule 2010 Permits Required

This Rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of an ATC application, the PEC Peaker Project is complying with the requirements of this Rule.

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

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As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install four new CTG with a PE greater than 2 lb/day for NO_X, SO_X, PM_{10}, CO, and VOC. BACT is triggered for NO_X, SO_X, PM_{10}, CO, and VOC since the PEs are greater than 2 lbs/day and the SSPE2 for CO is greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

The PE of ammonia is greater than 2.0 pounds per day for each of the four CTG's. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NOx. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

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As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new diesel-fired emergency IC engine powering a fire pump with a PE greater than 2 lb/day for NO_X, CO, and VOC. BACT is triggered for NO_X, CO, and VOC since the PEs are greater than 2 lbs/day and the SSPE2 for CO is greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

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As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new cooling tower with a PE greater than 2 lb/day for PM10. BACT is triggered for PM10 since the PE is greater than 2 lbs/day, as demonstrated in Section VII.C.5 of this document.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

c. Modification of emissions units – AIPE > 2 lb/day

As discussed in Section I above, there are no modified emissions units associated with this project; therefore BACT is not triggered.

d. Major Modification

As discussed in Section VII.C.7 above, this project does not constitute a Major Modification; therefore BACT is not triggered.

2. BACT Guideline

BACT Guideline 3.4.7, applies to each CTG. [Gas Turbine - = or > 50 MW, Uniform Load, without Heat Recovery] (See Appendix B)

BACT Guideline 3.1.4, applies to the diesel-fired emergency IC engine driving a fire pump. [Emergency Diesel I.C. Engine Driving a Fire Pump] (See Appendix B)

BACT Guideline 8.3.10, applies to the cooling tower. [Cooling Tower – Induced Draft, Evaporative Cooling] (See Appendix B)

3. Top-Down BACT Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

Pursuant to the attached Top-Down BACT Analysis (see Appendix C), BACT has been satisfied with the following:

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NO_X: 2.5 ppmvd @ 15% O2, based on a one-hour average (high temperature Selective Catalytic Reduction (SCR), or equal)
SO_X: PUC-regulated natural gas, LPG, or Non-PUC-regulated gas with = or < 0.75 grains S/100 scf
PM_{10}: Air inlet cooler/filter, lube oil vent coalescer (or equal) and either PUC regulated natural gas, LPG, or non-PUC-regulated gas with < 0.75 grains S/100 scf
CO: 6.0 ppmvd @ 15% O2 based on a three-hour average (Oxidation catalyst or equal)
VOC: 2.0 ppmvd @ 15% O2 based on a three-hour average (Oxidation catalyst or equal)

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NO_X: Certified NO_X emissions of 6.9 g/hp·hr or less
CO: None (UL certified)
VOC: None (UL certified)

C-7220-6-0

PM_{10}: Cellular Type Drift Eliminator

B. Offsets

1. Offset Applicability

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post Project Stationary Source Potential to Emit (SSPE2) equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The following table compares the post-project facility-wide annual emissions in order to determine if offsets will be required for this project.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
Post Project SSPE (SSPE2)	193,943	50,200	121,765	371,011	60,703
Offset Threshold	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	Yes	No	Yes	Yes	Yes

2. Quantity of Offsets Required

As seen above, the SSPE2 is greater than the offset thresholds for NO_X, PM10, CO, and VOC; therefore offset calculations will be required for this project.

Per Sections 4.7.2 and 4.7.3, the quantity of offsets in pounds per year for NO_X is calculated as follows for sources with an SSPE1 less than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = [(SSPE2 – ROT + ICCE) x DOR]

Where,
SSPE2 = Post Project Stationary Source Potential to Emit
ROT = Respective Offset Threshold, for the respective pollutant indicated in Section 4.5.3.
ICCE = Increase in Cargo Carrier Emissions
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

Per Section 4.6.2, emergency equipment that is used exclusively as emergency standby equipment for electrical power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year of non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power, is exempt from providing emission offsets. Therefore, permit unit C-7220-5-0 will be exempt from providing offsets and the emissions associated with this permit unit contributing to the SSPE2 should be removed prior to calculating actual offset amounts.

Offsets Required (lb/year) = [(SSPE2 – Emergency Equipment – ROT + ICCE) x DOR]

<u>NOx</u>

SSPE2 (NO_X)	= 193,943 lb/year
C-7220-5-0 (NO_X)	= 83 lb/year
Offset threshold (NO_X)	= 20,000 lb/year
ICCE	= 0 lb/year

Offsets Required (lb/year) = [(193,943 – 83 – 20,000 + 0) x DOR]
= 173,860 x DOR

The applicant has proposed the following quarterly hours of operation:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
1,100 hr	1,100 hr	1,600 hr	1,200 hr

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr without distance ratio):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
38,249	38,249	55,635	41,726

The applicant is proposing to use ERC Certificates S-2437-2, S-2362-2 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, an offset ratio of 1.5:1 is applicable and the amount of NO_X ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 173,860 x 1.5
= 260,790 lb NO_X/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
57,374	57,374	83,453	62,589

The applicant has stated that the facility plans to use ERC certificates S-2437-2 and S-2362-2 to offset the increases in NO_X emissions associated with this project. The above certificates have available quarterly NO_X credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #S-2437-2	22,379	22,627	22,876	22,876
ERC #S-2362-2	44,097	52,114	52,114	52,114
Total	66,476	74,741	74,990	74,990

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERCs Available	66,476	74,741	74,990	74,990
Offsets Required	57,374	57,374	83,453	62,589
Difference	9,102	17,367	-8,463	12,401

As shown above, there are not sufficient ERCs to cover the NOx offsets in the 3rd Quarter. Per Rule 2201 Section 4.13.8, NOx ERCs from the 2nd Quarter can be used to offset increases in the 3rd Quarter. Therefore, as seen above, the facility has sufficient credits to fully offset the quarterly NO_X emissions increases associated with this project.

PM10

SSPE2 (PM_{10}) = 121,765 lb/year
C-7220-5-0 (PM_{10}) = 3 lb/year
Offset threshold (PM_{10}) = 29,200 lb/year
ICCE = 0 lb/year

Offsets Required (lb/year) = [(121,765 – 3 – 29,200 + 0) x DOR]
= 92,562 x DOR

The applicant has proposed the following quarterly hours of operation:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
1,100 hr	1,100 hr	1,600 hr	1,200 hr

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr without distance ratio):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
20,364	20,364	29,620	22,215

The applicant is proposing to use ERC Certificates S-2431-4, S-2432-4, S-2433-4, S-2434-4, S-2436-4, S-2435-4, N-559-5, N-591-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, an offset ratio of 1.5:1 is applicable and the amount of PM10 ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 92,562 x 1.5
= 138,843 lb PM10/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
30,545	30,545	44,430	33,322

The applicant has stated that the facility plans to use ERC certificates S-2431-4, S-2432-4, S-2433-4, S-2434-4, S-2436-4, S-2435-4, N-559-5, N-591-5 to offset the increases in PM10 emissions associated with this project. The above certificates have available quarterly credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #S-2431-4	8,741	7,519	8,213	8,457
ERC #S-2432-4	904	923	981	961
ERC #S-2433-4	3,587	3,857	4,416	4,220
ERC #S-2434-4	3,382	3,622	3,173	3,855
ERC #S-2436-4	0	686	802	723
ERC #S-2435-4	0	1,079	1,058	951
Total	16,614	17,686	18,643	19,167
ERC #N-559-5	1,560	1,560	1,560	1,560
ERC #N-591-5	53,530	49,310	0	91,616

Project PM10 offset requirements

The applicant states PM10 and SOx ERC certificates S-2431-4, S-2432-4, S-2433-4, S-2434-4, S-2436-4, S-2435-4, N-559-5, N-591-5 will be utilized to supply the PM10 offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM10 Emissions to be offset: (at a 1.5:1 ratio):	30,545	30,545	44,430	33,322
Available ERCs from certificate S-2431-4:	8,741	7,519	8,213	8,457
ERCs applied from certificate S-2431-4 fully withdrawn as certificate S-2431-4:	-8,741	-7,519	-8,213	-8,457
Remaining ERCs from certificate S-2431-4:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio):	21,804	23,026	36,217	24,865

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 ratio):	21,804	23,026	36,217	24,865
Available ERCs from certificate S-2432-4:	904	923	981	961
ERCs applied from certificate S-2432-4 fully withdrawn as certificate S-2432-4:	-904	-923	-981	-961
Remaining ERCs from certificate S-2432-4:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio):	20,900	22,103	35,236	23,904

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 ratio):	20,900	22,103	35,236	23,904
Available ERCs from certificate S-2433-4:	3,587	3,857	4,416	4,220
ERCs applied from certificate S-2433-4 fully withdrawn as certificate S-2433-4:	-3,587	-3,857	-4,416	-4,220
Remaining ERCs from certificate S-2433-4:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio):	17,313	18,246	30,820	19,684

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 ratio):	17,313	18,246	30,820	19,684
Available ERCs from certificate S-2434-4:	3,382	3,622	3,173	3,855
ERCs applied from certificate S-2434-4 fully withdrawn as certificate S-2434-4:	-3,382	-3,622	-3,173	-3,855
Remaining ERCs from certificate S-2434-4:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio):	13,931	14,624	27,647	15,829

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 ratio):	13,931	14,624	27,647	15,829
Available ERCs from certificate S-2436-4:	0	686	802	723
ERCs applied from certificate S-2436-4 fully withdrawn as certificate S-2436-4:	0	-686	-802	-723
Remaining ERCs from certificate S-2436-4:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio):	13,931	13,938	26,845	15,106

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 ratio):	13,931	13,938	26,845	15,106
Available ERCs from certificate S-2435-4:	0	1,079	1,058	951
ERCs applied from certificate S-2435-4 fully withdrawn as certificate S-2435-4:	0	-1,079	-1,058	-951
Remaining ERCs from certificate S-2435-4:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio):	13,931	12,859	25,787	14,155

As seen above, the facility is lacking sufficient credits to fully offset the emissions increases for PM10.

As proposed by the applicant, in order to satisfy District offset requirements the applicant has proposed providing SOx reductions in place of PM10 reductions. District Rule 2201 Section 4.13.3 allows such interpollutant substitutions provided the applicant shows that the substitution will not cause or contribute to the violation of an ambient air quality standard and that the appropriate interpollutant offset ratio is utilized.

The applicant has stated that the facility plans to use ERC certificates N-559-5 and N-591-5 to offset the increases in PM10 emissions associated with this project. The above certificates have available quarterly credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #N-559-5	1,560	1,560	1,560	1,560
ERC #N-591-5	53,530	49,310	0	91,616
Total	55,090	50,870	1,560	93,176

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM10 and PM10 precursors (i.e. SOx) may be allowed. The applicant is proposing to use interpollutant offsets SOx for PM10 at an interpollutant ratio of 1.867:1 (see Appendix D).

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.867 = 2.80).

<u>Project SOx for PM10 offset requirements</u>

The applicant states SOx ERC certificates N-559-5 and N-591-5 will be utilized to supply the PM10 offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 ratio):	13,931	12,859	25,787	14,155
Remaining PM10 emissions to be offset with SOx ERCs (at a 1.5:1 distance ratio and a 1.867:1 interpollutant SOx:PM10 ratio):	26,009	24,008	48,144	26,427
Available ERCs from certificate N-559-5:	1,560	1,560	1,560	1,560
ERCs applied from certificate N-559-5 fully withdrawn as certificate N-559-5:	-1,560	-1,560	-1,560	-1,560
Remaining ERCs from certificate N-559-5:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.867:1 interpollutant SOx:PM10 ratio):	24,449	22,448	46,584	24,867

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 emissions to be offset with SOx ERCs (at a 1.5:1 distance ratio and a 1.867:1 interpollutant SOx:PM10 ratio):	24,449	22,448	46,584	24,867
Available ERCs from certificate N-591-5:	53,530	49,310	0	91,616
ERCs applied from certificate N-591-5 partially withdrawn:	-24,449	-22,448	0	-24,867
Remaining ERCs from certificate N-591-5:	29,081	26,862	0	66,749
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.867:1 interpollutant SOx:PM10 ratio):	0	0	46,584	0

Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SOx ERCs are being used to offset PM10 emissions, the above applies to the SOx ERCs.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 emissions to be offset with SOx ERCs (at a 1.5:1 distance ratio and a 1.867:1 interpollutant SOx:PM10 ratio):	0	0	46,584	0
Remaining ERCs from certificate N-591-5:	29,081	26,862	0	66,749
4th qtr. ERCs applied to 3rd qtr. ERCs:	0	0	46,584	-46,584
Remaining ERCs from certificate N-591-5:	29,081	26,862	46,584	20,165
ERCs applied from certificate N-591-5 partially withdrawn:	0	0	-46,584	0
Remaining ERCs from certificate N-591-5:	29,081	26,862	0	20,165
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.867:1 interpollutant SOx:PM10 ratio):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly PM10 emissions increases associated with this project.

<u>CO</u>

CO offsets are triggered by CO emissions in excess of 200,000 lb/year for the facility. As shown previously, the SSPE2 for CO, after this project, is 371,011 lb/year, so offset requirements are triggered.

However, pursuant to Section 4.6.1, "Emission Offsets shall not be required for the following: increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards (AAQS)."

The Technical Services Section of the San Joaquin Valley Unified Air Pollution Control District performed a CO modeling run, using the EPA AERMOD air dispersion model, to determine if the CO emissions from the new facility would exceed the State and Federal AAQS (Appendix F). Modeling of the worst case 1 hour and 8 hour CO impacts were performed. These values were added to the worst case ambient concentration (background) measured and compared to the ambient air quality standards. Results of the modeling are presented below:

Ambient Modeling Results for CO		
	1 hr std	**8 hr std**
AAQS (ug/m^3)	2000	500
Worst case ambient (background) (ug/m^3)	5,709	4,194
Modeled impact (ug/m^3)	9	5

This modeling demonstrates that the proposed increase in CO emissions will not cause a violation of the CO ambient air quality standards. Therefore, the increase in CO emissions is exempt from offsets pursuant to Rule 2201 Section 4.6.1.

VOC

SSPE2 (VOC) = 60,703 lb/year
C-7220-5-0 (VOC) = 7 lb/year
Offset threshold (VOC) = 20,000 lb/year
ICCE = 0 lb/year

Offsets Required (lb/year) = [(60,703 – 7 – 20,000 + 0) x DOR]
= 40,696 x DOR

The applicant has proposed the following quarterly hours of operation:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
1,100 hr	1,100 hr	1,600 hr	1,200 hr

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr without distance ratio):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
8,953	8,953	16,023	9,767

The applicant is proposing to use ERC Certificate S-2331-1 which has an original site of reduction greater than 15 miles from the location of this project. Therefore, an offset ratio of 1.5:1 is applicable and the amount of PM10 ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 40,696 x 1.5
= 61,044 lb VOC/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
13,430	13,430	19,534	14,651

The applicant has stated that the facility plans to use ERC certificate S-2465-1 to offset the increases in VOC emissions associated with this project. The applicant has purchased the quarterly VOC credits of the above certificate as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #S-2465-1	23,306	23,308	23,308	23,308

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

Proposed Rule 2201 (offset) Conditions:

- Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide NO_X emission reduction credits for the following quantity of emissions: 1st quarter - 38,249 lb, 2nd quarter - 38,249 lb, 3rd quarter - 55,635 lb, and fourth quarter - 41,726 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]
- Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide PM10 emission reduction credits for the following quantity of emissions: 1st quarter - 20,364 lb, 2nd quarter - 20,364 lb, 3rd quarter - 29,620 lb, and fourth quarter - 22,215 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). SOx ERCs may be used to offset PM10 increases at an interpollutant ratio of 1.867 lb-SOx : 1.0 lb-PM10. [District Rule 2201]
- Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter – 8,953 lb, 2nd quarter – 8,953 lb, 3rd quarter - 13,023 lb, and fourth quarter - 9,767 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]
- ERC Certificate Numbers S-2437-2, S-2362-2, S-2431-4, S-2432-4, S-2433-4, S-2434-4, S-2436-4, S-2435-4, N-559-5, N-591-5, S-2465-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Demonstration of Compliance. [District Rule 2201]

C. Public Notification

1. Applicability

Public noticing is required for:

a. Any new Major Source, which is a new facility that is also a Major Source,
b. Major Modifications,
c. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
d. Any project which results in the offset thresholds being surpassed, and/or
e. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.

a. New Major Source

New Major Sources are new facilities, which are also Major Sources. As shown in Section VII.C.5 above, the SSPE2 is greater than the Major Source threshold for NO_X, CO, and VOC. Therefore, public noticing is required for this project for new Major Source purposes because this facility is becoming a new Major Source.

b. Major Modification

As demonstrated in VII.C.7, this project does not constitute a Major Modification; therefore, public noticing for Major Modification purposes is not required.

c. PE > 100 lb/day

The PE2 for this new unit is compared to the daily PE Public Notice thresholds in the following table:

PE > 100 lb/day Public Notice Thresholds			
Pollutant	PE2 (lb/day) (each turbine)	Public Notice Threshold	Public Notice Triggered?
NO_X	261.1	100 lb/day	Yes
SO_X	60.2	100 lb/day	No
PM_{10}	144.0	100 lb/day	Yes
CO	560.4	100 lb/day	Yes
VOC	79.1	100 lb/day	No
NH3	285.6	100 lb/day	Yes

Therefore, public noticing for PE > 100 lb/day purposes is required.

d. Offset Threshold

The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	0	193,943	20,000 lb/year	Yes
SO_X	0	50,200	54,750 lb/year	No
PM_{10}	0	121,765	29,200 lb/year	Yes
CO	0	371,011	200,000 lb/year	Yes
VOC	0	60,703	20,000 lb/year	Yes

As detailed above, offset thresholds were surpassed for NO_X, PM10, CO, VOC with this project; therefore public noticing is required for offset purposes.

e. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary Source Potential to Emit (SSPE1), i.e. SSIPE = SSPE2 – SSPE1. The values for SSPE2 and SSPE1 are calculated according to Rule 2201, Sections 4.9 and 4.10, respectively. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

Stationary Source Increase in Permitted Emissions [SSIPE] – Public Notice					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO_x	193,943	0	193,943	20,000 lb/year	Yes
SO_x	50,200	0	50,200	20,000 lb/year	Yes
PM_{10}	121,765	0	121,765	20,000 lb/year	Yes
CO	371,011	0	371,011	20,000 lb/year	Yes
VOC	60,703	0	60,703	20,000 lb/year	Yes
NH_3	59,500	0	59,500	20,000 lb/year	Yes

As demonstrated above, the SSIPEs for NO_X, SO_X, PM10, CO, VOC, and NH3 were greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

2. Public Notice Action

As discussed above, public noticing is required for this project for new major source, PE in excess of 100 lb/day, offset threshold being surpassed, and SSIPE greater than 20,000 lb/year. The District shall public notice this project according to the requirements of Section 5.5.

D. Daily Emission Limits (DELs)

Daily Emissions Limitations (DELs) and other enforceable conditions are required by Section 3.15 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. Per Sections 3.15.1 and 3.15.2, the DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

C-7220-1-0 through '4-0

Proposed Rule 2201 (DEL) Conditions:

- Emission rates from the CTG, except during startup and shutdown periods, shall not exceed any of the following: NOx (as NO2) – 8.03 lb/hr and 2.5 ppmvd @ 15% O2;

VOC (as methane) – 2.67 lb/hr and 2.0 ppmvd @ 15% O2; CO – 11.81 lb/hr and 6.0 ppmvd @ 15% O2; PM10 – 6.00 lb/hr; or SOx (as SO2) – 2.51 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other pollutant emission limits are three hour rolling averages. [District Rules 2201 and 4703 and and 40 CFR 60.4320(a) & (b)]

- Daily emissions from the CTG shall not exceed any of the following limits: NOx (as NO2) – 261.1 lb/day; VOC – 79.1 lb/day; CO – 560.4 lb/day; PM10 – 144.0 lb/day; or SOx (as SO2) - 60.2 lb/day. [District Rule 2201]
- Ammonia (NH3) emissions shall not exceed either of the following limits: 11.90 lb/hr or 10 ppmvd @ 15% O2 (based on a 24 hour rolling average). [District Rules 2201 and 4102]

C-7220-5-0

Proposed Rule 2201 (DEL) Conditions:

- {edited 3485} Emissions from this IC engine shall not exceed any of the following limits: 4.5 g-NOx/bhp-hr, 0.6 g-CO/bhp-hr, or 0.4 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]
- {edited 3486} Emissions from this IC engine shall not exceed 0.15 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

C-7220-6-0

Proposed Rule 2201 (DEL) Condition:

- PM10 emission rate from the cooling tower shall not exceed 8.4 lb/day. [District Rule 2201]

E. Compliance Assurance

1. Source Testing

C-7220-1-0 through '4-0

District Rule 4703 requires NO_X and CO emission testing on an annual basis. The District Source Test Policy (APR 1705) requires annual testing for all pollutants controlled by catalysts. The control equipment will include a SCR system and an oxidation catalyst. Ammonia slip is an indicator of how well the SCR system is performing and PM_{10} emissions are a good indicator of how well the inlet air cooler/filter are performing.

Therefore, source testing for NO_X, VOC, CO, PM_{10}, and ammonia slip will be required within 120 days of initial operation and at least once every 12 months thereafter.

Also, initial source testing of NO_X, CO, and VOC startup emissions will be required for one gas turbine engine initially and not less than every seven years thereafter. If CEM data is not certifiable to determine compliance with NO_X and CO startup emission limits, then source testing to measure startup NO_X and CO mass emission rates shall be conducted at least once every 12 months. This testing will serve two purposes: to validate the startup emission estimates used in the emission calculations and to verify that the CEMs accurately measure startup emissions.

Each CTG will have a separate exhaust stack. The units will be equipped with CEMs for NO_X, CO, and O_2. Each CTG will be equipped with an individual CEM. Each CEM will have two ranges to allow accurate measurements of NO_X and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR Part 75.

40 CFR Part 60 subpart KKKK requires fuel nitrogen content testing. The District will accept the NO_X source testing required by District Rule 4703 as equivalent to fuel nitrogen content testing.

40 CFR Part 60 subpart KKKK requires that fuel sulfur content be monitored. Refer to the monitoring section of this document for a discussion of the fuel sulfur testing requirements.

C-7220-5-0

Pursuant to District Policy APR 1705, source testing is not required for emergency IC engines to demonstrate compliance with Rule 2201.

2. Monitoring

C-7220-1-0 through '4-0

Monitoring of NO_X emissions is required by District Rule 4703. The applicant has proposed a CEMS for NO_X.

CO monitoring is not specifically required by any applicable Rule or Regulation. Nevertheless, due to erratic CO emission concentrations during start-up and shutdown periods, it is necessary to limit the CO emissions on a pound per hour basis. Therefore, a CO CEMS is necessary to show compliance with the CO limits of this permit. The applicant has proposed a CO CEMS.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel nitrogen content. As stated in the Subpart KKKK compliance section of this document, the District will allow the annual NO_X source test to substitute for this requirement.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel sulfur content. The gas supplier, Pacific Gas & Electric (PG&E), may deliver gas with a sulfur content of up to 1.0 gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to require initial weekly testing for eight consecutive weeks and semi-annual fuel sulfur content testing thereafter if the fuel sulfur content remains below 1.0 gr/scf. Therefore, fuel sulfur content testing is required.

C-7220-6-0

District Rule 7012 requires hexavalent chromium concentration testing to be conducted at least once every six (6) months for non-wooden cooling towers subject to Section 5.2.3 of the rule. Since the cooling tower has never had hexavalent chromium containing compounds added to the circulating water, this unit is exempt from the monitoring requirements of the rule. Therefore, no monitoring will be required for this permit unit.

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201.

C-7220-1-0 through '4-0

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to section VIII.E.2 of this document for a discussion of the parameters that will be monitored.

C-7220-5-0

Recordkeeping is required to demonstrate compliance with the offset, public notification, and daily emission limit requirements of Rule 2201. As required by District Rule 4702, *Stationary Internal Combustion Engines - Phase 2*, this IC engine is subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rule 4702, will be discussed in Section VIII, *District Rule 4702*, of this evaluation.

C-7220-6-0

District Rule 7012 requires any person subject to Sections 5.2.2 and 5.2.3 of the rule to keep records of all circulating water tests performed. As discussed above, the cooling tower is exempt from the monitoring/testing requirements of the rule. Therefore, no recordkeeping will be required for this permit unit.

4. Reporting

C-7220-1-0 through '4-0

40 CFR Part 60 Subpart KKKK requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart KKKK requires the reporting of exceedences of the NO_X emission limit of the permit. Such reporting will be required.

C-7220-6-0

District Rule 7012 requires the facility submit a compliance plan to the APCO at least 90 days before the newly constructed cooling tower is operated. Such reporting will be required.

F. Ambient Air Quality Analysis

Section 4.14.1 of this Rule requires that an ambient air quality analysis (AAQA) be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Appendix F of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NO_X, CO, and SO_X. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X.

The proposed location is in a non-attainment area for PM_{10}. The increase in the ambient PM_{10} concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

Significance Levels					
Pollutant	Significance Levels ($\mu g/m^3$) - 40 CFR Part 51.165 (b)(2)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	1.0	5	N/A	N/A	N/A

Calculated Contribution					
Pollutant	Calculated Contributions ($\mu g/m^3$)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	0.13	1.2	N/A	N/A	N/A

As shown, the calculated contribution of PM_{10} will not exceed the EPA significance level. This project is not expected to cause or make worse a violation of an air quality standard.

G. Compliance Certification

Section 4.15.2 of this Rule requires the owner of a new Major Source or a source undergoing a Major Modification to demonstrate to the satisfaction of the District that all other Major Sources owned by such person and operating in California are in compliance or are on a schedule for compliance with all applicable emission limitations and standards. As discussed in Sections VIII-Rule 2201-C.1.a and VIII-Rule 2201-C.1.b, this facility is a new major source, therefore this requirement is applicable. Included in Appendix E is PEC's compliance certification.

Rule 2520 Federally Mandated Operating Permits

Since this facility's emissions exceed the major source thresholds of District Rule 2201, this facility is a major source. Pursuant to Rule 2520 Section 5.1, and as required by permit condition, the facility will have up to 12 months from the date of ATC issuance to either submit a Title V Application or comply with District Rule 2530 *Federally Enforceable Potential to Emit.*

Rule 2540 Acid Rain Program

The proposed CTGs are subject to the acid rain program as phase II units, i.e. they will be installed after 11/15/90 and each has a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the unit expects to generate electricity. The facility anticipates beginning commercial operation in August of 2009.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the NO_X and SO_X emissions and a relatively small quantity of SO_X allowances (from a national SO_X allowance bank) will be required as well as the use of a NO_X CEM.

<u>Proposed Rule 2540 Condition</u>:

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics

Section 2.0 states, "*The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after June 28, 1998.*" The applicant has provided the following analysis for Noncriteria pollutants/HAPs.

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[1]

In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). Any pollutant that may be emitted from the project and is on the federal New Source Review List and the federal Clean Air Act list has been evaluated.

[1] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission (CEC).

The applicant has supplied the following data.

Hazardous Air Pollutant Emissions
PEC – General Electric LMS100

Hazardous Air Pollutant	CATEF (mean) Emission Factor (lb/MMBtu)	CATEF (mean) Emission Factor (lb/MMcf)(1)	Maximum Hourly Emissions per Turbine (lb/hr) (2)	Maximum Annual Emissions per Turbine (lb/yr) (3)
1,3-Butadiene	1.24E-07	1.27E-04	1.13E-04	5.64E-01
Acetaldehyde	1.34E-04	1.37E-01	1.22E-01	6.09E+02
Acrolein	1.85E-05	1.89E-02	1.68E-02	8.40E+01
Benzene	1.30E-05	1.33E-02	1.18E-02	5.91E+01
Ethyl benzene	1.75E-05	1.79E-02	1.59E-02	7.95E+01
Formaldehyde	8.96E-04	9.17E-01	8.15E-01	4.07E+03
Hexane	2.53E-04	2.59E-01	2.30E-01	1.15E+03
Propylene	7.53E-04	7.71E-01	6.85E-01	3.42E+03
Propylene Oxide	4.67E-05	4.78E-02	4.25E-02	2.12E+02
Toluene	6.93E-05	7.10E-02	6.31E-02	3.15E+02
Xylenes	2.55E-05	2.61E-02	2.32E-02	1.16E+02
PAHs				
Benzo(a)anthracene	2.21E-08	2.26E-05	2.01E-05	1.00E-01
Benzo(a)pyrene	1.36E-08	1.39E-05	1.23E-05	6.17E-02
Benzo(b)fluoranthene	1.10E-08	1.13E-05	1.00E-05	5.02E-02
Benzo(k)fluoranthene	1.07E-08	1.10E-05	9.77E-05	4.89E-02
Chrysene	2.46E-08	2.52E-05	2.24E-05	1.12E-01
Dibenz(a,h)anthracene	2.29E-08	2.35E-05	2.09E-05	1.04E-01
Indeno(1,2,3-cd)pyrene	2.29E-08	2.35E-05	2.09E-05	1.04E+00
Naphthalene	1.62E-06	1.66E-03	1.47E-03	7.37E+00
Total			**2.03**	**10,124**

(1) Based on natural gas fuel HHV of 1,024 Btu/scf
(2) Maximum fuel flow 909.7 MMBtu/hr, includes startups, warm-ups, shutdowns, and maintenance
(3) Based on a maximum hourly turbine fuel use of 5,000 hr/yr

Hazardous Air Pollutant Emissions
PEC – Cooling Tower(1)

Hazardous Air Pollutant	Concentration in Cooling Tower Return Water(2)	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (lb/yr)
Arsenic	0.021 ug/L	4.35E-09	2.18E-05
Total		**4.35E-09**	**2.18E-05**

(1) Emissions calculated from maximum circulating water rate of 27,600 gal/min, drift eliminator control of 0.0005%, operation of 5,000 hr/yr.
(2) Three cycles of concentration, five cells in cooling tower.

Hazardous Air Pollutant Emissions
PEC – Emergency Diesel Firewater Pump

Hazardous Air Pollutant	Emission Factor (g/hp-hr)	Maximum Hourly Emissions (lb/hr)	Maximum Annual Emissions (lb/yr)
Diesel Particulate	0.15	5.29E-02	2.75E+00
Total		**0.0529**	**2.75**

Therefore, as emissions of each individual HAP are below 10 tons per year and total HAP emissions are below 25 tons per year, the PEC will not be a major air toxics source and the provisions of this rule do not apply.

To ensure this source is not a major air toxics source, the following conditions will be listed on the permit:

- Hazardous Air Pollutant (HAP) emissions shall not exceed 25 tpy all HAPS or 10 tpy any single HAP. [District Rule 4002]
- Permittee shall conduct an initial speciated HAPS and total VOC source test for one of the GTEs (C-7220-1, '2, '3 or '4), by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. PEC shall correlate the total HAPS emissions rate and the single highest HAP emission rate to the VOC mass emission determined during the speciated HAPs source test. Initial and annual compliance with the HAPS emissions limit (25 tpy all HAPs or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates for the GTEs (C-7220-1, '2, '3, and '4) determined during initial and annual compliance source testing and the correlation between VOC emissions and HAP(s). [District Rule 4002]

Rule 4001 New Source Performance Standards (NSPS)

40 CFR 60 – Subpart GG

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after October 3, 1977. PEC has indicated that the installation and construction of the proposed turbines will be completed in 2009. Therefore, these turbines meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(a), states that this subpart applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005. PEC has indicated that the installation and construction of the proposed turbines will be completed in 2009. Therefore, these turbines also meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed above, 40 CFR 60 Subpart KKKK is applicable to these proposed turbines. Therefore, they are exempt from the requirements of 40 CFR 60 Subpart GG and no further discussion is required.

40 CFR 60 – Subpart KKKK

40 CFR Part 60 Subpart KKKK applies to all stationary gas turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The proposed gas turbines involved in this project have a rating of 909.7 MMBtu/hr and will be installed after February 18, 2005. Therefore, this subpart applies to these gas turbines.

Subpart KKKK established requirements for nitrogen oxide (NO_X) and sulfur dioxide (SO_X) emissions.

Section 60.4320 - Standards for Nitrogen Oxides:

Paragraph (a) states that NO_X emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X. Table 1 states that new turbines firing natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr shall meet a NO_X emissions limit of 15 ppmvd @ 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh).

PEC is proposing a NO_X emission concentration limit of 2.5 ppmvd @ 15% O_2 for each turbine. Therefore, the proposed turbines will be operating in compliance with the NO_X emission requirements of this subpart. The following condition will ensure continued compliance with the requirements of this section:

- Emission rates from the CTG, except during startup or shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 8.03 lb/hr and 2.5 ppmvd @ 15% O2; SOx (as SO2) – 2.51 lb/hr; PM10 – 6.00 lb/hr; CO – 11.81 lb/hr and 6.0 ppmvd @ 15% O2; or VOC (as methane) – 2.67 lb/hr and 2.0 ppmvd @ 15% O2. NO_X (as NO_2) emission limits are one hour rolling averages. All other pollutant emission concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

Section 60.4330 - Standards for Sulfur Dioxide:

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output; or
(2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

PEC is proposing to burn natural gas fuel in each of these turbines with a maximum sulfur content of 1.0 grain/ 100 scf (0.00285 lb/MMBtu). Therefore, the proposed turbines will be operating in compliance with the SO_X emission requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- This unit shall exclusively burn PUC-regulated natural gas with a sulfur content no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

Section 60.4335 – NO_X Compliance Demonstration, with Water or Steam Injection:

Paragraph (a) states that when a turbine is using water or steam injection to reduce NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

Paragraph (b) states that alternatively, an operator may use continuous emission monitoring, as follows:

(1) Install, certify, maintain and operate a continuous emissions monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and
(2) For units complying with the output-based standard, install, calibrate, maintain and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and
(3) For units complying with the output based standard, install, calibrate, maintain and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and
(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

PEC operates each of these turbines with water injection. They are proposing to install, certify, maintain and operate a CEMS consisting of a NO_X monitor and an O_2 monitor to determine hourly NO_X emission rate in ppm. They are not proposing to comply with the output-based NO_X emission standards listed in Table 1. Therefore, the proposed CEMS satisfies the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The turbine shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703 and 40 CFR 60.4335(b)(1)]
- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703 and 40 CFR 60.4335(b)(1)]

Section 60.4340 – NO_X Compliance Demonstration, without Water or Steam Injection:

This section specifies the requirements for units not equipped with water or steam injection. As discussed above, PEC is proposing to use water injection to reduce NO_X emissions in each of these turbines. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4345 – CEMS Equipment Requirements:

Paragraph (a) states that each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

Paragraph (c) states that each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

PEC will be required to install and operate a NO_X CEMS in accordance with the requirements of this section. As discussed above, PEC is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]
- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

Section 60.4350 – CEMS Data and Excess NO_X Emissions:

Section 60.4350 states that for purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

PEC is proposing to monitor the NO_X emissions rates from these turbines with a CEMS. The CEMS system will be used to determine if, and when, any excess NO_X emissions are released to the atmosphere from the turbine exhaust stacks. The CEMS will be operated in accordance with the methods and procedures described above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

Section 60.4355 – Parameter Monitoring Plan:

This section sets fourth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions. As discussed above, PEC is proposing to install CEMS on each of these turbines that will directly measure NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content:

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

PEC is proposing to operate these turbines on natural gas that contains a maximum sulfur content of 1.0 grains/100 scf. Primarily, the natural gas supplier should be able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates compliance with the natural gas sulfur content limit. However, PEC has asked that the option of either using a purchase contract, tariff sheet or transportation contract or actually physically monitoring the sulfur content be incorporated into their permit.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

When actually required to physically monitor the sulfur content in the fuel burned in these turbines, PEC is proposing a custom monitoring schedule. The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every six months. If any six month monitoring period shows an exceedance, weekly monitoring shall resume. PEC is proposing to follow this same pre-approved fuel sulfur content monitoring scheme for these turbines. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) demonstrated within 60 days after the end of the commissioning period and monitored weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess NO_X Emissions:

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, PEC is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the NO_X emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document document proper operation of the NO_X emission controls. PEC is not proposing to monitor combustion parameters that document proper operation of the NO_X emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

The following condition will ensure continued compliance with the requirements of this section:

- Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

Section 60.4385 – Excess SO_X Emissions:

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

PEC will be following the definitions and procedures specified above for determining periods of excess SO_X emissions. Therefore, the proposed turbines will be operating in compliance with the requirements of this section.

Sections 60.4375, 60.4380, 60.4385 and 60.4395 – Reporting:

These sections establish the reporting requirements for each turbine. These requirements include methods and procedures for submitting reports of monitoring parameters, annual performance tests, excess emissions and periods of monitor downtime. PEC is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – NO_X Performance Testing:

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Susequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set forth the requirements for the methods that are to be used during source testing.

PEC will be required to source test the exhaust of these turbines within 120 days of initial startup and at least once every 12 months thereafter. They will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- Source testing to measure the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 120 days after initial operation and at least once every twelve months thereafter. [District Rules 1081 and 4703 and 40 CFR 60.4400(a)]
- The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia – EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Section 60.4405 – Initial CEMS Relative Accuracy Testing:

Section 60.4405 states that if you elect to install and certify a NO_X-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). PEC has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4410 – Parameter Monitoring Ranges:

Section 60.4410 sets fourth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls. As discussed above, PEC is proposing to install a CEMS system to monitor the NO_X emissions from each of these turbines and is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415– SO_X Performance Testing:

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

   (i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

   (ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

PEC is proposing to periodically determine the sulfur content of the fuel combusted in each of these turbines when valid purchase contracts, tariff sheets or transportation contract is not available. The sulfur content will be determined using the methods specified above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the SO_2 concentration in the exhaust stream. PEC is not proposing to measure the SO_2 in the exhaust stream of these turbines. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected and no further discussion is required.

Rule 4002 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

Pursuant to Section 2.0, *"All sources of hazardous air pollution shall comply with the standards, criteria, and requirements set forth therein;"* therefore, the requirements of this rule applies to the PEC. But there are no applicable requirements for a non-major HAPs source. PEC will conduct an initial speciated HAPS compliance source test to demonstrate that the facility is not a major HAPS source.

Proposed Rule 4002 Condition:

- Permittee shall conduct an initial speciated HAPS and total VOC source test for one of the GTEs (C-7220-1, '2, '3 or '4), by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. PEC shall correlate the total HAPS emissions rate and the single highest HAP emission rate to the VOC mass emission determined during the speciated HAPs source test. Initial and annual compliance with the HAPS emissions limit (25 tpy all HAPs or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates for the GTEs (C-7220-1, '2, '3, and '4) determined during initial and annual compliance source testing and the correlation between VOC emissions and HAP(s). [District Rule 4002]

Rule 4101 Visible Emissions

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

C-7220-1-0 through '4-0

The CTGs lube oil vents will be limited by permit condition to not have visible emissions, except for three minutes in any hour, greater than 5% opacity as a BACT requirement and the exhaust stack emissions will be limited by permit condition to no greater than 20% opacity except for three minutes in any hour. Therefore compliance is expected.

Proposed Rule 4101 Conditions:

- No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

- Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rules 2201 and 4101]

C-7220-5-0 and '6-0

The IC engine and cooling tower are not expected to have visible emissions, excluding uncombined water vapor for the cooling tower, greater than 20% opacity. Therefore, compliance is expected.

<u>Proposed Rule 4101 Condition</u>:

- No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – Risk Management Policy for Permitting New and Modified Sources specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Appendix F), the total facility prioritization score including this project was greater than one. Therefore, a health risk assessment was required to determine the short-term acute and long-term chronic exposure from this project.

The cancer risk for this project is shown below:

HRA Summary		
Unit	Cancer Risk	T-BACT Required
C-7220-1-0	0.05 per million	No
C-7220-2-0	0.05 per million	No
C-7220-3-0	0.05 per million	No
C-7220-4-0	0.05 per million	No
C-7220-5-0	0.32 per million	No
C-7220-6-0	0.00 per million	No

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 10 in a million). As outlined by the HRA Summary in Appendix F of this report, the emissions increases for this project was determined to be less than significant.

C-7220-5-0

- The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]
- The engine shall be operated only for maintenance, testing, and required regulatory purposes shall not exceed 52 hours per year. [District Rules 2201 and 4702]

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

C-7220-1-0 through '4-0

$$\text{PM Conc. (gr/scf)} = \frac{\text{(PM emission rate)} \times \text{(7,000 gr/lb)}}{\text{(Exhaust gas flow rate)} \times \text{(60 min/hr)} \times \text{(24 hr/day)}}$$

PM_{10} emission rate = 144.0 lb/day. Assuming 100% of PM is PM_{10}
Exhaust Gas Flow = 361,394 scfm

PM Conc. (gr/scf) = [(144.0 lb/day) * (7,000 gr/lb)] ÷ [(361,394 ft^3/min) * (60 min/hr) * (24 hr/day)]
PM Conc. = 0.0019 gr/scf

C-7220-5-0

$$0.15 \frac{g-PM_{10}}{bhp-hr} \times \frac{1g-PM}{0.96g-PM_{10}} \times \frac{1\,bhp-hr}{2{,}542.5\,Btu} \times \frac{10^6\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = 0.037 \frac{grain-PM}{dscf}$$

C-7220-6-0

PM Conc. (gr/scf) = $\dfrac{\text{(PM emission rate) x (7,000 gr/lb)}}{\text{(Exhaust gas flow rate) x (60 min/hr) x (24 hr/day)}}$

PM_{10} emission rate = 8.4 lb/day. Assuming 100% of PM is PM_{10}
Exhaust Gas Flow = 10.569E8 scfm

PM Conc. (gr/scf) = [(8.4 lb/day) * (7,000 gr/lb)] ÷ [(10.569E8 ft^3/min) * (60 min/hr) * (24 hr/day)]
PM Conc. = 0.00000004 gr/scf

Calculated emissions are well below the allowable emissions level. Therefore, compliance with Rule 4201 is expected.

Proposed Rule 4201 Condition:

- Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4202 Particulate Matter Emission Rate

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to the four CTGs or the engine. However, it does apply to the cooling tower.

C-7220-6-0

Weight rate/cooling tower = 27,600 gal/min * 60 min/hr * 8.34 lb/gal ÷ 2,000 lb/ton
= 6,906 ton/hr

Rule 4202 emission limit = 17.31 * $P^{0.16}$ (where P greater than 30 tons/hr)
= 17.31 * $(6,906)^{0.16}$
= 71.2 lb/hr

The cooling tower has a PM_{10} emission rate of 0.35 lb/hr (8.4 lb/day @ 24 hr/day). All cooling tower PM emissions are PM_{10}. As shown above, the cooling tower PM emissions will be less than allowed by Rule 4202. Compliance is expected.

Rule 4301 Fuel Burning Equipment

Rule 4301 limits air contaminant emissions from fuel burning equipment as defined in the rule. Section 3.1 defines fuel burning equipment as "any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer".

C-7220-1-0 through '4-0

The CTGs primarily produce power mechanically, i.e. the products of combustion pass across the power turbine blades which causes the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft which is rotated to produce electricity. Because the CTGs primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment. Rule 4301 does not apply to the affected equipment.

C-7220-5-0

The emergency use IC engines produces power mechanically. Therefore, they do not meet the definition of fuel burning equipment. . Rule 4301 does not apply to the affected equipment.

Rule 4701 Internal Combustion Engines – Phase 1

Pursuant to Section 7.5.2.3 of District Rule 4702, as of June 1, 2006 District Rule 4701 is no longer applicable to diesel-fired emergency standby or emergency IC engines. Therefore, this diesel-fired emergency IC engine will comply with the requirements of District Rule 4702 and no further discussion is required.

Rule 4702 Internal Combustion Engines – Phase 2

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) from internal combustion engines.

This rule applies to any internal combustion engine with a rated brake horsepower greater than 50 horsepower.

Pursuant to Section 4.3, except for the requirements of Section 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following conditions:

1) The engine is operated exclusively to preserve or protect property, human life, or public health during a disaster or state of emergency, such as a fire or flood, and
2) Except for operations associated with Section 4.3.1.1, the engine is limited to operate no more than 100 hours per calendar year as determined by an operational nonresettable elapsed operating time meter, for periodic maintenance, periodic readiness testing, and readiness testing during and after repair work of the engine, and

3) The engine is operated with a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, the emergency IC engine involved with this project will only have to meet the requirements of Section 6.2.3 of this Rule.

Section 6.2.3 requires that an owner claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and submitted to the APCO upon request and at the end of each calendar year in a manner and form approved by the APCO. Therefore, the following conditions will be listed on the ATC to ensure compliance:

- {3488} This engine shall be operated only for maintenance, testing, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 52 hours per calendar year. [District Rule 4702 and 17 CCR 93115]
- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]
- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

In addition, the following condition will be listed on the ATC to ensure compliance:

- {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

Rule 4703 Stationary Gas Turbines

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts. The facility proposes to install four 100 MW gas turbines, therefore this rule applies.

Section 5.1.1 (Tier I) of this rule limits the NO_X emissions from stationary gas turbine systems greater than 10 MW, and equipped with Selective Catalytic Reduction (SCR), based on the following equation:

$$NO_X\ (\text{ppmv} @ 15\%\ O_2) = 9 \times \left(\frac{EFF}{25}\right)$$

Where EFF is the higher of EFF_1 or EFF_2 where:

$$EFF_1 = \frac{3{,}412 \frac{Btu}{kW-hr}}{\text{Actual Heat Rate @ HHV}\left(\frac{Btu}{kW-hr}\right)} \times 100\text{, and } EFF_2 = EFF_{MFR}\frac{LHV}{HHV}$$

$$EFF_2 \quad = EFF_{mfr} * (LHV/HHV)$$

Calculated data indicates that the Actual Heat Rate @ HHV is 7,815 Btu/kW-hr. Therefore:

$$EFF_1 \quad = \frac{3{,}412 \frac{Btu}{kW-hr}}{7{,}815 \frac{Btu}{kW-hr}} \times 100 \quad = \quad 43.66\%$$

$$NO_X \text{ limit utilizing } EFF_1 \quad = \quad 9 \times \left(\frac{43.66}{25}\right) \quad = \quad 15.7 \text{ ppmvd} @ 15\%\ O_2$$

EFF_2 calculations are not necessary since Rule 4703 emission limits will be no lower than 9 ppmv NO_X and the proposed turbines will be limited to a maximum of 2.5 ppmv NO_X @ 15% O_2 (based on a 1-hour average), therefore compliance is expected.

Section 5.1.2 (Tier 2) of this rule limits the NO_X emissions from simple cycle, stationary gas turbine systems rated at greater than 10 MW and allowed to operate more than 876 hours per year to 5 ppmv @ 15% O_2 (Standard option) and 3 ppmv @ 15% O_2 (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed turbines will be limited to 2.5 ppmv @ 15% O_2 (based on a 1-hour average), therefore compliance with this section is expected. The following condition will ensure continued compliance with the requirements of this section:

- Emission rates from the CTG, except during startup or shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 8.03 lb/hr and 2.5 ppmvd @ 15% O2; SOx (as SO2) - 2.51 lb/hr; PM10 - 6.00 lb/hr; CO - 11.81 lb/hr and 6.0 ppmvd @ 15% O2; or VOC (as methane) - 2.67 lb/hr and 2.0 ppmvd @ 15% O2. NOx (as NO2) emission limits are one hour rolling averages. All other pollutant emission concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

<u>Section 5.2 – CO Emission Requirements:</u>

Per Table 5-3 of section 5.2, the CO emissions concentration from the proposed turbines must be less than 200 ppmvd @ 15% O_2. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. However, District practice is to have an applicant demonstrate compliance with the CO emissions on a turbine with three hour averaging periods. Therefore, compliance with the CO emission limit shall be demonstrated by an average over a three hour period.

PEC is proposing a CO emission concentration limit of 6 ppmvd @ 15% O_2 and will demonstrate compliance using three hour averaging periods. Therefore, the proposed turbines will be operating the turbine in compliance with the CO emission requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- Emission rates from the CTG, except during startup or shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 8.03 lb/hr and 2.5 ppmvd @ 15% O2; SOx (as SO2) - 2.51 lb/hr; PM10 - 6.00 lb/hr; CO - 11.81 lb/hr and 6.0 ppmvd @ 15% O2; or VOC (as methane) - 2.67 lb/hr and 2.0 ppmvd @ 15% O2. NOx (as NO2) emission limits are one hour rolling averages. All other pollutant emission concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

Section 5.3 – Startup and Shutdown Requirements:

This section states that the emission limit requirements of Sections 5.1.1, 5.1.2 or 5.2 shall not apply during startup, shutdown, or a reduced load period provided an operator complies with the requirements specified below:

- The duration of each startup or each shutdown shall not exceed two hours, and the duration of each reduced load period shall not exceed one hour, except as provided below.
- The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup, shutdown, or a reduced load period.
- An operator may submit an application to allow more than two hours for each startup or each shutdown or more than one hour for each reduced load period provided the operator meets all of the conditions specified in the rule.

PEC is proposing to incorporate startup and shutdown provisions into the operating requirements for each of the proposed turbines. They have proposed that the duration of each startup or shutdown event will last no more than two hours. The SCR system and oxidation catalyst will be in operation during startup and shutdown in order to minimize emissions insofar as technologically feasible during startups and shutdowns. Therefore, the proposed turbines will be operating in compliance with the startup and shutdown requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- During periods of startup, CTG exhaust emission rates shall not exceed any of the following limits: NOx (as NO2) - 44.40 lb/hr, SOx – 2.51 lb/hr, PM10 6.00 lb/hr, CO - 106.60 lb/hr, or VOC - 7.60 lb/hr, based on one hour averages. [District Rule 2201]
- During periods of shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NOx (as NO2) - 34.29 lb/hr, SOx – 2.51 lb/hr, PM10 6.00 lb/hr, CO - 268.57 lb/hr, or VOC - 17.14 lb/hr, based on one hour averages. [District Rule 2201]
- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by

the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

- The duration of each startup or shutdown shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]
- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

Section 6.2 - Monitoring and Record Keeping:

Section 6.2.1 requires the owner to operate and maintain continuous emissions monitoring equipment for NO_X and oxygen, or install and maintain APCO-approved alternate monitoring. As discussed earlier in this evaluation, the applicant operates a Continuous Emissions Monitoring System (CEMS) that monitors the NO_X and oxygen content of the turbine exhaust. Therefore, the requirements of this section have been satisfied. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOX, CO and O2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201, and 4703 and 40 CFR 60.4335(b)(1)]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO_X control devices. Each of the proposed turbines will be equipped with an SCR system that is designed to control NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO_X emissions. The proposed turbines will not be installed until 2008. Therefore, they were not in operation prior to August 18, 1994 and the requirements of this section are not applicable. No further discussion is required.

Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. PEC will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbines will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, and 4703]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure NO_X output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for NO_X available or when the continuous emissions monitoring system is not operating properly. PEC will be required, by permit condition, to submit information correlating the NO_X control system operating parameters to the associated measured NO_X output. Therefore, the proposed turbines will be operating in compliance with the control system operating parameter requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall submit to the District, before issuance of the Permit to Operate, information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when no continuous emission monitoring data for NOx is available or when the continuous emission monitoring system is not operating properly. [District Rule 4703]

Section 6.2.6 requires the facility to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. PEC will be required to maintain records of each item listed above. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing; evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201, and 4703 and 40 CFR 60.8(d)]

- The permittee shall maintain the following records: quarterly hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

Section 6.2.7 establishes recordkeeping requirements for units that are exempt pursuant to the requirements of Section 4.2. Each of the proposed turbines is subject to the requirements of this rule. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.8 requires owners or operators performing startups or shutdowns to keep records of the duration of each startup and shutdown. As discussed in the Section 6.2.6 discussion above for this rule, PEC will be required, by permit condition, to maintain records of the date, time and duration or each startup and shutdown. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule.

<u>Sections 6.3 and 6.4 - Compliance Testing:</u>

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas NO_X and CO concentrations. The turbines operated by PEC are subject to the provisions of Section 5.0 of this rule. Therefore, each turbine is required to test annually to demonstrate compliance with the exhaust gas NO_X and CO concentrations. The following condition will ensure continued compliance with the requirements of this section:

- Source testing to measure the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 120 days after initial operation and at least once every twelve months thereafter. [District Rules 1081 and 4703 and 40 CFR 60.4400(a)]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, each of the proposed turbines will be allowed to operate up to 4,000 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 specifies source testing requirements for units that are equipped with intermittently operated auxiliary burners. PEC is not proposing to operate any of these turbines with auxiliary burners. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.4 states that the facility must demonstrate compliance annually with the NO_X and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.
- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.
- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.
- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following conditions will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia – EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

- HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a),(b) and District Rule 4703, 6.4.5]

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this rule. Therefore, compliance with the requirements of Rule 4703 is expected and no further discussion is required.

Rule 4801 Sulfur Compounds

Per Section 3.1, a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2% by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes:

C-7220-1-0 through '4-0

The sulfur of the natural gas fuel is 1.0 gr/100 dscf.

The ratio of the volume of the SO_x exhaust to the entire exhaust for one MMBtu of fuel combusted is:

Volume of SO_x: $V = \dfrac{n \cdot R \cdot T}{P}$

Where:

- n = number of moles of SO_x produced per MMBtu of fuel.
- Weight of SO_x as SO_2 is 64 lb/(lb-mol)
- $n = \dfrac{0.00285\ lb}{MMBtu} \times \dfrac{1\ (lb-mol)}{64\ lb} = 0.000045\ (lb-mol)$
- $R = \dfrac{0.7302\ ft^3 \cdot atm}{(lb-mol)^\circ R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_X per MMBtu is:

$$V = \frac{n \cdot R \cdot T}{P}$$

$$V = \frac{0.000045\ (lb - mol) \cdot \dfrac{0.7302\ ft^3 \cdot atm}{(lb - mol)\ °R} \cdot 500\ °R}{1\ atm}$$

$$V = 0.016\ ft^3$$

Since the total volume of exhaust per MMBtu is 8,578 scf, the ratio of SO_X volume to exhaust volume is

$$= \frac{0.016}{8{,}578} = 0.0000019 = 1.9\ ppmv = 0.00019\%\ by\ volume$$

1.9 ppmv ≤ 2000 ppmv, therefore the turbines are expected to comply with Rule 4801.

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Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot °\text{R}}$

$$\frac{0.000015\ lb - S}{lb - fuel} \times \frac{7.1\ \text{lb}}{\text{gal}} \times \frac{64\ \text{lb} - SO_2}{32\ \text{lb} - \text{S}} \times \frac{1\ \text{MMBtu}}{9{,}051\ \text{scf}} \times \frac{1\ \text{gal}}{0.137\ \text{MMBtu}} \times \frac{\text{lb} - \text{mol}}{64\ \text{lb} - SO_2} \times \frac{10.73\ \text{psi} - \text{ft}^3}{\text{lb} - \text{mol} - °\text{R}} \times \frac{520°\text{R}}{14.7\ \text{psi}} \times 1{,}000{,}000 = 1.0\ \text{ppmv}$$

Since 1.0 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition will be listed on the permit to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

Rule 7012 Hexavalent Chromium – Cooling Towers

The proposed cooling towers are new and will not use hexavalent chromium, therefore they meet the exemption criteria in section 4.1.2. Therefore, the cooling tower is exempt from the requirements of Rule 7012 except for sections 5.2.1, 6.1, and 7.1.

Section 5.2.1 requires that no hexavalent chromium compounds be added after 9/16/91 (intended to apply to cooling towers that previously used hexavalent chromium). A permit condition will be added to satisfy this requirement.

Section 6.1 requires that the owner/operator of a new cooling tower submit a compliance plan at least 90 days before it is operated containing business information, location of cooling tower, type and materials of construction, and a statement regarding the use or non use of hexavalent chromium. A permit condition will be added to satisfy this requirement.

Section 7.1 requires that the permittee pay permit filing fees associated with the cooling tower. PEC has paid such fees.

Compliance is expected.

Proposed Rule 7012 Conditions:

C-7220-6-0

- Permittee shall submit cooling tower design details including the cooling tower type, drift eliminator design details, and materials of construction to the District at least 90 days before the tower is operated. [District Rule 7012]
- No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

Rule 8011 General Requirements

The definitions, exemptions, requirements, administrative requirements, recordkeeping requirements, and test methods set forth in this rule are applicable to all rules under Regulation VIII (Fugitive PM10 Prohibitions) of the Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District.

Rule 8021 Construction, Demolition, Excavation, Extraction and Other Earthmoving Acitivites

The purpose of this rule is to limit fugitive dust emissions from construction, demolition, excavation, and other earthmoving activities. It requires the use of control measures to maintain visible dust emissions (VDE) under the 20% opacity requirement.

PEC will commit to the use of dust control measures (e.g., water, approved chemical stabilizers, etc.) during construction to maintain opacity to a level below 20% per Rule 8021 requirements. Compliance with the requirements of this rule is anticipated.

Proposed Rule 8021 Condition:

- Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]
- An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

- An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

Rule 8031 Bulk Materials

Pursuant to Section 2.0, this rule is applicable to the outdoor handling, storage, and transport of any bulk material. The following condition will be included on the permit to satisfy the requirements of the rule.

Proposed Rule 8031 Condition:

- Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

Rule 8051 Open Areas

Pursuant to Section 2.0, this rule is applicable to any open area having 3.0 acres or more of disturbed surface area, that has remained undeveloped, unoccupied, unused or vacant for more than seven days. The following condition will be included on the permit to satisfy the requirements of the rule.

Proposed Rule 8051 Condition:

- Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

Rule 8061 Paved and Unpaved Roads

Pursuant to Section 2.0, this rule applies to any new or existing public or private paved or unpaved road, road construction project, or road modification project. The following condition will be included on the permit to satisfy the requirements of the rule.

Proposed Rule 8061 Condition:

- Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

Rule 8071 Unpaved Vehicle/Equipment Traffic Areas

Pursuant to Section 2.0, this rule applies to any unpaved vehicle/equipment traffic area of 1.0 acre or larger. The following condition will be included on the permit to satisfy the requirements of the rule.

Proposed Rule 8071 Condition:

- Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]
- Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]
- On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]
- Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

Title 13 California Code of Regulations (CCR), Section 2423 – Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment (Required by Title 17 CCR, Section 93115 for New Emergency Diesel IC Engines)

Particulate Matter and VOC + NO_X, and CO Exhaust Emissions Standards:

This regulation stipulates that off-road compression-ignition engines shall not exceed the following applicable emissions standards.

Title 13 CCR, Section 2423 lists a diesel particulate emission standard of 0.22 g/bhp-hr (with 1.341 bhp/kW, equivalent to 0.30 g/kW-hr) for 2003 - 2006 model year engines with maximum power ratings of 100.6 - 174.2 bhp (equivalent to 75 - 130 kW). The PM standards given in Title 13 CCR, Section 2423 are less stringent than the PM standards given in Title 17 CCR, Section 93115 (ATCM), thus the ATCM standards are the required standards and will be discussed in the following section.

Title 17 CCR, Section 93115, (e)(2)(A)(3)(b) stipulates that new stationary emergency diesel-fueled CI engines (> 50 bhp) must meet the VOC + NO_X, and CO standards for off-road engines of the same model year and maximum rated power as specified in the Off-Road Compression-Ignition Engine Standards (Title 13 CCR, Section 2423) or the Tier 1 standards for an off-road engine if no standards have been established for an off-road engine of the same model year and maximum rated power.

In addition, Title 17 CCR, Section 93115, (e)(2)(A)(4)(a)(II) allows new direct-drive emergency fire pump engines to meet the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (title 13 CCR, section 2423) three years after the date the standards are applicable for off-road engines with the same maximum rated power. For this project the proposed emergency diesel IC engine will be used to power a firewater pump, and is a new installation. The proposed emergency diesel IC engine meets the Tier 2 or Tier 3 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines on the applicable dates specified.

The engine involved with this project is a certified 2006 model engine. The following table compares the requirements of Title 13 CCR, Section 2423 to the emissions factors for the 160 bhp John Deere model #6068T diesel-fired emergency IC engine as given by the manufacturer (for NO_X + VOC and PM emissions).

Requirements of Title 13 CCR, Section 2423							
Source	Maximum Rated Power	Model Year	NO_X	VOC	NO_X + VOC	CO	PM
Title 13 CCR, §2423	100.6 – 174.2 bhp (75 - 130 kW)	2000-2002 (Tier 1)	6.9 g/bhp-hr (9.2 g/kW-hr)	--	--	--	--
Title 13 CCR, §2423	100.6 – 174.2 bhp (75 - 130 kW)	2003-2006 (Tier 2)	--	--	4.9 g/bhp-hr (6.6 g/kW-hr)	3.7 g/bhp-hr (5.0 g/kW-hr)	0.22 g/bhp-hr (0.30 g/kW-hr)
Title 13 CCR, §2423	100.6 – 174.2 bhp (75 - 130 kW)	2007 and later (Tier 3)	--	--	3.0 g/bhp-hr (4.0 g/kW-hr)	3.7 g/bhp-hr (5.0 g/kW-hr)	0.22 g/bhp-hr (0.30 g/kW-hr)
John Deere, Model #6068T	160 bhp	2006	4.5 g/bhp-hr (6.0 g/kW-hr)	0.4 g/bhp-hr (0.5 g/kW-hr)	4.90 g/bhp-hr (6.6 g/kW-hr)	0.6 g/bhp-hr (0.8 g/kW-hr)	0.15 g/bhp-hr (0.20 g/kW-hr)
Meets Standard?			N/A	N/A	Yes	Yes	Yes

As presented in the table above, the proposed engine will satisfy the requirements of this section and compliance is expected.

The engine manufacturer's data for this engine lists a NO_X + VOC emission factor of 4.90 g/bhp-hr, a CO emission factor of 0.60 g/bhp-hr, and a PM_{10} emissions factor of 0.15 g/bhp-hr, all of which satisfy the requirements of 13 CCR, Section 2423. Therefore, the following conditions will be listed on the ATC to ensure compliance:

- {edited 3485} Emissions from this IC engine shall not exceed any of the following limits: 4.5 g-NOx/bhp-hr, 0.6 g-CO/bhp-hr, or 0.4 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- {edited 3486} Emissions from this IC engine shall not exceed 0.15 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

Right of the District to Establish More Stringent Standards:

This regulation also stipulates that the District:

1. May establish more stringent diesel PM, NO_X + VOC, VOC, NO_X, and CO emission rate standards; and
2. May establish more stringent limits on hours of maintenance and testing on a site-specific basis; and
3. Shall determine an appropriate limit on the number of hours of operation for demonstrating compliance with other District rules and initial start-up testing

The District has not established more stringent standards at this time. Therefore, the standards previously established in this Section will be utilized.

Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

Emergency Operating Requirements:

This regulation stipulates that no owner or operator shall operate any new or in-use stationary diesel-fueled compression ignition (CI) emergency standby engine, in response to the notification of an impending rotating outage, unless specific criteria are met.

Fuel and Fuel Additive Requirements:

This regulation also stipulates that as of January 1, 2006 an owner or operator of a new or in-use stationary diesel-fueled CI emergency standby engine shall fuel the engine with CARB Diesel Fuel.

Since the engine involved with this project is a new or in-use stationary diesel-fueled CI emergency standby engine, these fuel requirements are applicable. Therefore, the following condition will be listed on the ATC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

At-School and Near-School Provisions:

This regulation stipulates that no owner or operator shall operate a new stationary emergency diesel-fueled CI engine, with a PM_{10} emissions factor > than 0.01 g/bhp-hr, for non-emergency use, including maintenance and testing, during the following periods:

1. Whenever there is a school sponsored activity, if the engine is located on school grounds, and

2. Between 7:30 a.m. and 3:30 p.m. on days when school is in session, if the engine is located within 500 feet of school grounds.

The District has verified that the engine is not located within 500 feet of a K-12 school. Therefore, conditions prohibiting non-emergency usage of the engine during school hours will not be placed on the permit.

Recordkeeping Requirements:

This regulation stipulates that as of January 1, 2005, each owner or operator of an emergency diesel-fueled CI engine shall keep a monthly log of usage that shall list and document the nature of use for each of the following:

a. Emergency use hours of operation;
b. Maintenance and testing hours of operation;
c. Hours of operation for emission testing;
d. Initial start-up hours; and
e. If applicable, hours of operation to comply with the testing requirements of National Fire Protection Association (NFPA) 25 — "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition;
f. Hours of operation for all uses other than those specified in sections 'a' through 'd' above; and
g. For in-use emergency diesel-fueled engines, the fuel used. The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:
    I. Identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above;
    II. Amount of fuel purchased;
    III. Date when the fuel was purchased;
    IV. Signature of owner or operator or representative of owner or operator who received the fuel; and
    V. Signature of fuel provider indicating fuel was delivered.

The proposed new emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions will be listed on the ATC to ensure compliance:

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

PM Emissions and Hours of Operation Requirements for New Diesel Engines:

This regulation stipulates that as of January 1, 2005, no person shall operate any new stationary emergency diesel-fueled CI engine that has a rated brake horsepower greater than 50, unless it meets all of the following applicable emission standards and operating requirements.

1. Emits diesel PM at a rate greater than 0.01 g/bhp-hr or less than or equal to 0.15 g/bhp-hr; or
2. Meets the current model year diesel PM standard specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (Title 13 CCR, Section 2423), whichever is more stringent; and
3. Does not operate more than 50 hours per year for maintenance and testing purposes. Engine operation is not limited during emergency use and during emissions source testing to show compliance with the ATCM.

The proposed emergency diesel IC engine powering a firewater pump is exempt from the PM emissions rate limitation because the engine is rated at 49.6 to 174.2 bhp (as discussed previously in the Title 13 CCR, Section 2423 compliance section) and is also exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions will be listed on the ATC to ensure compliance:

- {edited 3486} Emissions from this IC engine shall not exceed 0.15 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]
- {3488} This engine shall be operated only for maintenance, testing, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 52 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

California Environmental Quality Act (CEQA)

It has been determined that the project has the potential to adversely affect the environment and therefore subject to requirements of the California Environmental Quality Act (CEQA). The California Energy Commission (CEC) is the lead agency for CEQA. Upon satisfaction of the CEQA requirements for this project, the CEC will issue a Certification to PEC approving construction and operation of the power plant. The District's FDOC conditions will be incorporated into the CEC's Certification for this power plant project. Therefore, CEQA requirements will be satisfied prior to approval of construction.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project

California Health & Safety Code, Section 44300 (Air Toxic "Hot Spots")

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.
2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.
3. The district issues a permit authorizing construction or operation of the new facility.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than ten (10) in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

IX. Recommendation

Compliance with all applicable prohibitory rules and regulations is expected. Pending a successful NSR Public Noticing period, issue the Final Determination of Compliance for the facility subject to the conditions presented in Appendix A.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
C-7220-1-0	3020-08B-H	100 MW	$11,323
C-7220-2-0	3020-08B-H	100 MW	$11,323
C-7220-3-0	3020-08B-H	100 MW	$11,323
C-7220-4-0	3020-08B-H	100 MW	$11,323
C-7220-5-0	3020-10-B	160 hp	$100
C-7220-6-0	999-999	Electrical Generation Component	$0.00

APPENDIX A
Determination of Compliance Conditions

EQUIPMENT DESCRIPTION, UNIT C-7220-1-0:
100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST

1. Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide NO_X emission reduction credits for the following quantity of emissions: 1st quarter - 38,249 lb, 2nd quarter - 38,249 lb, 3rd quarter - 55,635 lb, and fourth quarter - 41,726 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

2. Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide PM10 emission reduction credits for the following quantity of emissions: 1st quarter - 20,364 lb, 2nd quarter - 20,364 lb, 3rd quarter - 29,620 lb, and fourth quarter - 22,215 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). SOx ERCs may be used to offset PM10 increases at an interpollutant ratio of 1.867 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

3. Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter – 8,953 lb, 2nd quarter – 8,953 lb, 3rd quarter - 13,023 lb, and fourth quarter - 9,767 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

4. ERC Certificate Numbers S-2437-2, S-2362-2, S-2431-4, S-2432-4, S-2433-4, S-2434-4, S-2436-4, S-2435-4, N-559-5, N-591-5, S-2465-1 (or certificates split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Demonstration of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Demonstration of Compliance. [District Rule 2201]

5. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

6. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

7. The owner/operator of the Panoche Energy Center (PEC) shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. Conditions #8 through #18 shall apply only during the commissioning period as defined below. Unless otherwise indicated, Conditions #20 through #80 shall apply after the commissioning period has ended. [District Rule 2201]

8. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the PEC construction contractor to insure safe and reliable steady state operation of the gas turbines and associated electrical delivery systems. [District Rule 2201]

9. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing, completed final plant tuning, and is available for commercial operation. [District Rule 2201]

10. No more than two of the turbines operating under C-7220-1, C-7220-2, C-7220-3 or C-7220-4 shall be commissioned at any one time. [District Rule 2201]

11. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

12. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

13. Coincident with the steady-state operation of the SCR system and the oxidation catalyst at loads greater than 50% and after installation and tuning of the emission controls, NOx, CO, and VOC emissions from this unit shall comply with the limits specified in condition #29. [District Rule 2201]

14. The permittee shall submit a plan to the District at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not limited to, the tuning of the combustors, the installation and operation of the SCR system and the oxidation catalyst, the installation, calibration, and testing of the NOx and CO continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

15. Emission rates from the CTG, during the commissioning period, shall not exceed any of the following limits: NOx (as NO2) - 187.00 lb/hr; PM10 – 6.00 lb/hr; CO – 309.75 lb/hr; or VOC (as methane) – 17.14 lb/hr. [District Rule 2201]

16. During the commissioning period, the permittee shall demonstrate NOx and CO compliance with condition #15 through the use of properly operated and maintained continuous emissions monitors and recorders as specified in condition #12. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). [District Rule 2201]

17. The continuous emissions monitors specified in these permit conditions shall be installed, calibrated and operational prior to the first firing of the unit. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emissions concentrations. [District Rule 2201]

18. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst of units C-7220-1, '2, '3, and '4 shall not exceed 800 hours total during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 800 firing hours without abatement shall expire. Records of the commissioning hours of operation for units C-7220-1, '2, '3, and '4 shall be maintained. [District Rule 2201]

19. The total mass emissions of NOx, SOx, PM10, CO, and VOC that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in condition #38. NOx and CO total mass emissions will be determined from CEMs data and SOx, PM10, and VOC total mass emissions will be calculated. [District Rule 2201]

20. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

21. Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

22. The owner or operator shall submit to the District, before issuance of the Permit to Operate, information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when no continuous emission monitoring data for NOx is available or when the continuous emission monitoring system is not operating properly. [District Rule 4703]

23. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

24. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

25. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

26. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

27. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for a period or periods not exceeding three minutes in any one hour. [District Rules 2201 and 4101]

28. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

29. Emission rates from the CTG, except during startup or shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 8.03 lb/hr and 2.5 ppmvd @ 15% O2; SOx (as SO2) – 2.51 lb/hr; PM10 – 6.00 lb/hr; CO – 11.81 lb/hr and 6.0 ppmvd @ 15% O2; or VOC (as methane) – 2.67 lb/hr and 2.0 ppmvd @ 15% O2. NO_X (as NO_2) emission limits are one hour rolling averages. All other pollutant emission concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

30. Ammonia (NH3) emissions shall not exceed either of the following limits: 11.90 lb/hr or 10 ppmvd @ 15% O2 (based on a 24 hour rolling average). [District Rules 2201 and 4102]

31. During periods of startup, CTG exhaust emission rates shall not exceed any of the following limits: NOx (as NO2) – 44.40 lb/hr, SOx – 2.51 lb/hr, PM10 6.00 lb/hr, CO - 106.60 lb/hr, or VOC - 7.60 lb/hr, based on one hour averages. [District Rules 2201]

32. During periods of shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NOx (as NO2) – 34.29 lb/hr, SOx – 2.51 lb/hr, PM10 6.00 lb/hr, CO – 268.57 lb/hr, or VOC - 17.14 lb/hr, based on one hour averages. [District Rules 2201]

33. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

34. The duration of each startup or shutdown shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

35. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

36. Daily emissions from the CTG shall not exceed any of the following limits: NOx (as NO2) – 261.1 lb/day; VOC – 79.1 lb/day; CO – 560.4 lb/day; PM10 – 144.0 lb/day; or SOx (as SO2) - 60.2 lb/day. [District Rule 2201]

37. Quarterly hours of operation shall not exceed any of the following: 1st Quarter - 1,100 hours, 2nd Quarter - 1,100 hours, 3rd Quarter - 1,600 hours, or 4th Quarter - 1,200 hours. [District Rule 2201]

38. Annual emissions from the CTG, calculated on a twelve consecutive month rolling basis, shall not exceed any of the following: NOx (as NO2) - 48,465 lb/year; SOx (as SO2) - 12,550 lb/year; PM10 - 30,000 lb/year; CO - 92,750 lb/year; or VOC - 15,174 lb/year. [District Rule 2201]

39. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

40. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

41. Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = average ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rule 2201]

42. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-7220-1, C-7220-2, C-7220-3, or C-7220-4) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rule 1081]

43. Hazardous Air Pollutant (HAP) emissions shall not exceed 25 tpy all HAPS or 10 tpy any single HAP. [District Rule 4002]

44. Permittee shall conduct an initial speciated HAPS and total VOC source test for one of the GTEs (C-7220-1, '2, '3 or '4), by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. PEC shall correlate the total HAPS emissions rate and the single highest HAP emission rate to the VOC mass emission determined during the speciated HAPs source test. Initial and annual compliance with the HAPS emissions limit (25 tpy all HAPs

or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates for the GTEs (C-7220-1, '2, '3, and '4) determined during initial and annual compliance source testing and the correlation between VOC emissions and HAP(s). [District Rule 4002]

45. Source testing to measure the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 120 days after initial operation and at least once every twelve months thereafter. [District Rules 1081 and 4703 and 40 CFR 60.4400(a)]

46. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) shall be demonstrated within 60 days after the end of the commissioning period and monitored weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

47. The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia – EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

48. HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a),(b) and District Rule 4703, 6.4.5]

49. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

50. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]

51. Compliance demonstration (source testing) shall be District witnessed or authorized and samples shall be collected by a certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

52. The turbine shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703 and 40 CFR 60.4335(b)(1)]

53. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703 and 40 CFR 60.4335(b)(1)]

54. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

55. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

56. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

57. The owner/operator shall perform a relative accuracy test audit (RATA) for the NOx, CO, and O2 CEMs as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

58. Results of the CEM system shall be averaged over a one hour period for NOx emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

59. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

60. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other

methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

61. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

62. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

63. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

64. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

65. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

66. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

67. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

68. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing; evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201, and 4703 and 40 CFR 60.8(d)]

69. The permittee shall maintain the following records: quarterly hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

70. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, and 4703]

71. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

72. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

73. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

74. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

75. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

76. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

77. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

78. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

79. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

80. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-7220-2-0:
100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST

1. Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide NO_X emission reduction credits for the following quantity of emissions: 1st quarter - 38,249 lb, 2nd quarter - 38,249 lb, 3rd quarter - 55,635 lb, and fourth quarter - 41,726 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

2. Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide PM10 emission reduction credits for the following quantity of emissions: 1st quarter - 20,364 lb, 2nd quarter - 20,364 lb, 3rd quarter - 29,620 lb, and fourth quarter - 22,215 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). SOx ERCs may be used to offset PM10 increases at an interpollutant ratio of 1.867 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

3. Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter – 8,953 lb, 2nd quarter – 8,953 lb, 3rd quarter - 13,023 lb, and fourth quarter - 9,767 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

4. ERC Certificate Numbers S-2437-2, S-2362-2, S-2431-4, S-2432-4, S-2433-4, S-2434-4, S-2436-4, S-2435-4, N-559-5, N-591-5, S-2465-1 (or certificates split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Demonstration of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Demonstration of Compliance. [District Rule 2201]

5. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

6. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

7. The owner/operator of the Panoche Energy Center (PEC) shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. Conditions #8 through #18 shall apply only during the commissioning period as defined below. Unless otherwise indicated, Conditions #20 through #80 shall apply after the commissioning period has ended. [District Rule 2201]

8. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the PEC construction contractor to insure safe and reliable steady state operation of the gas turbines and associated electrical delivery systems. [District Rule 2201]

9. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing, completed final plant tuning, and is available for commercial operation. [District Rule 2201]

10. No more than two of the turbines operating under C-7220-1, C-7220-2, C-7220-3 or C-7220-4 shall be commissioned at any one time. [District Rule 2201]

11. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

12. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

13. Coincident with the steady-state operation of the SCR system and the oxidation catalyst at loads greater than 50% and after installation and tuning of the emission controls, NOx, CO, and VOC emissions from this unit shall comply with the limits specified in condition #29. [District Rule 2201]

14. The permittee shall submit a plan to the District at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not limited to, the tuning of the combustors, the installation and operation of the SCR system and the oxidation catalyst, the installation, calibration, and testing of the NOx and CO continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

15. Emission rates from the CTG, during the commissioning period, shall not exceed any of the following limits: NOx (as NO2) - 187.00 lb/hr; PM10 – 6.00 lb/hr; CO – 309.75 lb/hr; or VOC (as methane) – 17.14 lb/hr. [District Rule 2201]

16. During the commissioning period, the permittee shall demonstrate NOx and CO compliance with condition #15 through the use of properly operated and maintained continuous emissions monitors and recorders as specified in condition #12. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). [District Rule 2201]

17. The continuous emissions monitors specified in these permit conditions shall be installed, calibrated and operational prior to the first firing of the unit. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emissions concentrations. [District Rule 2201]

18. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst of units C-7220-1, '2, '3, and '4 shall not exceed 800 hours total during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 800 firing hours without abatement shall expire. Records of the commissioning hours of operation for units C-7220-1, '2, '3, and '4 shall be maintained. [District Rule 2201]

19. The total mass emissions of NOx, SOx, PM10, CO, and VOC that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in condition #38. NOx and CO total mass emissions will be determined from CEMs data and SOx, PM10, and VOC total mass emissions will be calculated. [District Rule 2201]

20. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

21. Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

22. The owner or operator shall submit to the District, before issuance of the Permit to Operate, information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when no continuous emission monitoring data for NOx is available or when the continuous emission monitoring system is not operating properly. [District Rule 4703]

23. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

24. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

25. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

26. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

27. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for a period or periods not exceeding three minutes in any one hour. [District Rules 2201 and 4101]

28. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

29. Emission rates from the CTG, except during startup or shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 8.03 lb/hr and 2.5 ppmvd @ 15% O2; SOx (as SO2) – 2.51 lb/hr; PM10 – 6.00 lb/hr; CO – 11.81 lb/hr and 6.0 ppmvd @ 15% O2; or VOC (as methane) – 2.67 lb/hr and 2.0 ppmvd @ 15% O2. NO_X (as NO_2) emission limits are one hour rolling averages. All other pollutant emission concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

30. Ammonia (NH3) emissions shall not exceed either of the following limits: 11.90 lb/hr or 10 ppmvd @ 15% O2 (based on a 24 hour rolling average). [District Rules 2201 and 4102]

31. During periods of startup, CTG exhaust emission rates shall not exceed any of the following limits: NOx (as NO2) – 44.40 lb/hr, SOx – 2.51 lb/hr, PM10 6.00 lb/hr, CO - 106.60 lb/hr, or VOC - 7.60 lb/hr, based on one hour averages. [District Rules 2201]

32. During periods of shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NOx (as NO2) – 34.29 lb/hr, SOx – 2.51 lb/hr, PM10 6.00 lb/hr, CO – 268.57 lb/hr, or VOC - 17.14 lb/hr, based on one hour averages. [District Rules 2201]

33. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

34. The duration of each startup or shutdown shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

35. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

36. Daily emissions from the CTG shall not exceed any of the following limits: NOx (as NO2) – 261.1 lb/day; VOC – 79.1 lb/day; CO – 560.4 lb/day; PM10 – 144.0 lb/day; or SOx (as SO2) - 60.2 lb/day. [District Rule 2201]

37. Quarterly hours of operation shall not exceed any of the following: 1st Quarter - 1,100 hours, 2nd Quarter - 1,100 hours, 3rd Quarter - 1,600 hours, or 4th Quarter - 1,200 hours. [District Rule 2201]

38. Annual emissions from the CTG, calculated on a twelve consecutive month rolling basis, shall not exceed any of the following: NOx (as NO2) - 48,465 lb/year; SOx (as SO2) - 12,550 lb/year; PM10 - 30,000 lb/year; CO - 92,750 lb/year; or VOC - 15,174 lb/year. [District Rule 2201]

39. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

40. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

41. Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = average ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rule 2201]

42. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-7220-1, C-7220-2, C-7220-3, or C-7220-4) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rule 1081]

43. Hazardous Air Pollutant (HAP) emissions shall not exceed 25 tpy all HAPS or 10 tpy any single HAP. [District Rule 4002]

44. Permittee shall conduct an initial speciated HAPS and total VOC source test for one of the GTEs (C-7220-1, '2, '3 or '4), by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. PEC shall correlate the total HAPS emissions rate and the single highest HAP emission rate to the VOC mass emission determined during the speciated HAPs source test. Initial and annual compliance with the HAPS emissions limit (25 tpy all HAPs

or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates for the GTEs (C-7220-1, '2, '3, and '4) determined during initial and annual compliance source testing and the correlation between VOC emissions and HAP(s). [District Rule 4002]

45. Source testing to measure the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 120 days after initial operation and at least once every twelve months thereafter. [District Rules 1081 and 4703 and 40 CFR 60.4400(a)]

46. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) shall be demonstrated within 60 days after the end of the commissioning period and monitored weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

47. The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia – EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

48. HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a),(b) and District Rule 4703, 6.4.5]

49. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

50. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]

51. Compliance demonstration (source testing) shall be District witnessed or authorized and samples shall be collected by a certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

52. The turbine shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703 and 40 CFR 60.4335(b)(1)]

53. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703 and 40 CFR 60.4335(b)(1)]

54. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

55. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

56. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

57. The owner/operator shall perform a relative accuracy test audit (RATA) for the NOx, CO, and O2 CEMs as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

58. Results of the CEM system shall be averaged over a one hour period for NOx emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

59. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

60. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other

methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

61. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

62. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

63. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

64. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

65. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

66. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

67. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

68. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing; evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201, and 4703 and 40 CFR 60.8(d)]

69. The permittee shall maintain the following records: quarterly hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

70. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, and 4703]

71. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

72. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

73. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

74. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

75. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

76. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

77. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

78. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

79. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

80. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-7220-3-0:
100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #3 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST

1. Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide NO_X emission reduction credits for the following quantity of emissions: 1st quarter - 38,249 lb, 2nd quarter - 38,249 lb, 3rd quarter - 55,635 lb, and fourth quarter - 41,726 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

2. Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide PM10 emission reduction credits for the following quantity of emissions: 1st quarter - 20,364 lb, 2nd quarter - 20,364 lb, 3rd quarter - 29,620 lb, and fourth quarter - 22,215 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). SOx ERCs may be used to offset PM10 increases at an interpollutant ratio of 1.867 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

3. Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter – 8,953 lb, 2nd quarter – 8,953 lb, 3rd quarter - 13,023 lb, and fourth quarter - 9,767 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

4. ERC Certificate Numbers S-2437-2, S-2362-2, S-2431-4, S-2432-4, S-2433-4, S-2434-4, S-2436-4, S-2435-4, N-559-5, N-591-5, S-2465-1 (or certificates split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Demonstration of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Demonstration of Compliance. [District Rule 2201]

5. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

6. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

7. The owner/operator of the Panoche Energy Center (PEC) shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. Conditions #8 through #18 shall apply only during the commissioning period as defined below. Unless otherwise indicated, Conditions #20 through #80 shall apply after the commissioning period has ended. [District Rule 2201]

8. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the PEC construction contractor to insure safe and reliable steady state operation of the gas turbines and associated electrical delivery systems. [District Rule 2201]

9. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing, completed final plant tuning, and is available for commercial operation. [District Rule 2201]

10. No more than two of the turbines operating under C-7220-1, C-7220-2, C-7220-3 or C-7220-4 shall be commissioned at any one time. [District Rule 2201]

11. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

12. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

13. Coincident with the steady-state operation of the SCR system and the oxidation catalyst at loads greater than 50% and after installation and tuning of the emission controls, NOx, CO, and VOC emissions from this unit shall comply with the limits specified in condition #29. [District Rule 2201]

14. The permittee shall submit a plan to the District at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not limited to, the tuning of the combustors, the installation and operation of the SCR system and the oxidation catalyst, the installation, calibration, and testing of the NOx and CO continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

15. Emission rates from the CTG, during the commissioning period, shall not exceed any of the following limits: NOx (as NO_2) - 187.00 lb/hr; PM10 – 6.00 lb/hr; CO – 309.75 lb/hr; or VOC (as methane) – 17.14 lb/hr. [District Rule 2201]

16. During the commissioning period, the permittee shall demonstrate NOx and CO compliance with condition #15 through the use of properly operated and maintained continuous emissions monitors and recorders as specified in condition #12. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). [District Rule 2201]

17. The continuous emissions monitors specified in these permit conditions shall be installed, calibrated and operational prior to the first firing of the unit. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emissions concentrations. [District Rule 2201]

18. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst of units C-7220-1, '2, '3, and '4 shall not exceed 800 hours total during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 800 firing hours without abatement shall expire. Records of the commissioning hours of operation for units C-7220-1, '2, '3, and '4 shall be maintained. [District Rule 2201]

19. The total mass emissions of NOx, SOx, PM10, CO, and VOC that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in condition #38. NOx and CO total mass emissions will be determined from CEMs data and SOx, PM10, and VOC total mass emissions will be calculated. [District Rule 2201]

20. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

21. Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

22. The owner or operator shall submit to the District, before issuance of the Permit to Operate, information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when no continuous emission monitoring data for NOx is available or when the continuous emission monitoring system is not operating properly. [District Rule 4703]

23. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

24. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

25. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

26. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

27. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for a period or periods not exceeding three minutes in any one hour. [District Rules 2201 and 4101]

28. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

29. Emission rates from the CTG, except during startup or shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 8.03 lb/hr and 2.5 ppmvd @ 15% O2; SOx (as SO2) – 2.51 lb/hr; PM10 – 6.00 lb/hr; CO – 11.81 lb/hr and 6.0 ppmvd @ 15% O2; or VOC (as methane) – 2.67 lb/hr and 2.0 ppmvd @ 15% O2. NO_X (as NO_2) emission limits are one hour rolling averages. All other pollutant emission concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

30. Ammonia (NH3) emissions shall not exceed either of the following limits: 11.90 lb/hr or 10 ppmvd @ 15% O2 (based on a 24 hour rolling average). [District Rules 2201 and 4102]

31. During periods of startup, CTG exhaust emission rates shall not exceed any of the following limits: NOx (as NO2) – 44.40 lb/hr, SOx – 2.51 lb/hr, PM10 6.00 lb/hr, CO - 106.60 lb/hr, or VOC - 7.60 lb/hr, based on one hour averages. [District Rules 2201]

32. During periods of shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NOx (as NO2) – 34.29 lb/hr, SOx – 2.51 lb/hr, PM10 6.00 lb/hr, CO – 268.57 lb/hr, or VOC - 17.14 lb/hr, based on one hour averages. [District Rules 2201]

33. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

34. The duration of each startup or shutdown shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

35. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

36. Daily emissions from the CTG shall not exceed any of the following limits: NOx (as NO2) – 261.1 lb/day; VOC – 79.1 lb/day; CO – 560.4 lb/day; PM10 – 144.0 lb/day; or SOx (as SO2) - 60.2 lb/day. [District Rule 2201]

37. Quarterly hours of operation shall not exceed any of the following: 1st Quarter - 1,100 hours, 2nd Quarter - 1,100 hours, 3rd Quarter - 1,600 hours, or 4th Quarter - 1,200 hours. [District Rule 2201]

38. Annual emissions from the CTG, calculated on a twelve consecutive month rolling basis, shall not exceed any of the following: NOx (as NO2) - 48,465 lb/year; SOx (as SO2) - 12,550 lb/year; PM10 - 30,000 lb/year; CO - 92,750 lb/year; or VOC - 15,174 lb/year. [District Rule 2201]

39. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

40. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

41. Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = average ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rule 2201]

42. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-7220-1, C-7220-2, C-7220-3, or C-7220-4) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rule 1081]

43. Hazardous Air Pollutant (HAP) emissions shall not exceed 25 tpy all HAPS or 10 tpy any single HAP. [District Rule 4002]

44. Permittee shall conduct an initial speciated HAPS and total VOC source test for one of the GTEs (C-7220-1, '2, '3 or '4), by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. PEC shall correlate the total HAPS emissions rate and the single highest HAP emission rate to the VOC mass emission determined during the speciated HAPs source test. Initial and annual compliance with the HAPS emissions limit (25 tpy all HAPs

or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates for the GTEs (C-7220-1, '2, '3, and '4) determined during initial and annual compliance source testing and the correlation between VOC emissions and HAP(s). [District Rule 4002]

45. Source testing to measure the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 120 days after initial operation and at least once every twelve months thereafter. [District Rules 1081 and 4703 and 40 CFR 60.4400(a)]

46. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) shall be demonstrated within 60 days after the end of the commissioning period and monitored weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

47. The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia – EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

48. HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a),(b) and District Rule 4703, 6.4.5]

49. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

50. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]

51. Compliance demonstration (source testing) shall be District witnessed or authorized and samples shall be collected by a certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

52. The turbine shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703 and 40 CFR 60.4335(b)(1)]

53. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703 and 40 CFR 60.4335(b)(1)]

54. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

55. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

56. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

57. The owner/operator shall perform a relative accuracy test audit (RATA) for the NOx, CO, and O2 CEMs as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

58. Results of the CEM system shall be averaged over a one hour period for NOx emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

59. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

60. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other

methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

61. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

62. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

63. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

64. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30^{th} day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

65. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

66. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

67. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

68. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing; evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201, and 4703 and 40 CFR 60.8(d)]

69. The permittee shall maintain the following records: quarterly hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

70. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, and 4703]

71. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

72. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

73. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

74. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

75. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

76. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

77. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

78. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

79. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

80. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-7220-4-0:
100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #4 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST

1. Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide NO_X emission reduction credits for the following quantity of emissions: 1st quarter - 38,249 lb, 2nd quarter - 38,249 lb, 3rd quarter - 55,635 lb, and fourth quarter - 41,726 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

2. Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide PM10 emission reduction credits for the following quantity of emissions: 1st quarter - 20,364 lb, 2nd quarter - 20,364 lb, 3rd quarter - 29,620 lb, and fourth quarter - 22,215 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). SOx ERCs may be used to offset PM10 increases at an interpollutant ratio of 1.867 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

3. Prior to initial operation of C-7220-1, '2, '3, and '4, permittee shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter – 8,953 lb, 2nd quarter – 8,953 lb, 3rd quarter - 13,023 lb, and fourth quarter - 9,767 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

4. ERC Certificate Numbers S-2437-2, S-2362-2, S-2431-4, S-2432-4, S-2433-4, S-2434-4, S-2436-4, S-2435-4, N-559-5, N-591-5, S-2465-1 (or certificates split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Demonstration of Compliance shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Demonstration of Compliance. [District Rule 2201]

5. Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

6. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

7. The owner/operator of the Panoche Energy Center (PEC) shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. Conditions #8 through #18 shall apply only during the commissioning period as defined below. Unless otherwise indicated, Conditions #20 through #80 shall apply after the commissioning period has ended. [District Rule 2201]

8. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the PEC construction contractor to insure safe and reliable steady state operation of the gas turbines and associated electrical delivery systems. [District Rule 2201]

9. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing, completed final plant tuning, and is available for commercial operation. [District Rule 2201]

10. No more than two of the turbines operating under C-7220-1, C-7220-2, C-7220-3 or C-7220-4 shall be commissioned at any one time. [District Rule 2201]

11. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

12. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

13. Coincident with the steady-state operation of the SCR system and the oxidation catalyst at loads greater than 50% and after installation and tuning of the emission controls, NOx, CO, and VOC emissions from this unit shall comply with the limits specified in condition #29. [District Rule 2201]

14. The permittee shall submit a plan to the District at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not limited to, the tuning of the combustors, the installation and operation of the SCR system and the oxidation catalyst, the installation, calibration, and testing of the NOx and CO continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

15. Emission rates from the CTG, during the commissioning period, shall not exceed any of the following limits: NOx (as NO_2) - 187.00 lb/hr; PM10 – 6.00 lb/hr; CO – 309.75 lb/hr; or VOC (as methane) – 17.14 lb/hr. [District Rule 2201]

16. During the commissioning period, the permittee shall demonstrate NOx and CO compliance with condition #15 through the use of properly operated and maintained continuous emissions monitors and recorders as specified in condition #12. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). [District Rule 2201]

17. The continuous emissions monitors specified in these permit conditions shall be installed, calibrated and operational prior to the first firing of the unit. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emissions concentrations. [District Rule 2201]

18. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst of units C-7220-1, '2, '3, and '4 shall not exceed 800 hours total during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 800 firing hours without abatement shall expire. Records of the commissioning hours of operation for units C-7220-1, '2, '3, and '4 shall be maintained. [District Rule 2201]

19. The total mass emissions of NOx, SOx, PM10, CO, and VOC that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in condition #38. NOx and CO total mass emissions will be determined from CEMs data and SOx, PM10, and VOC total mass emissions will be calculated. [District Rule 2201]

20. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

21. Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

22. The owner or operator shall submit to the District, before issuance of the Permit to Operate, information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when no continuous emission monitoring data for NOx is available or when the continuous emission monitoring system is not operating properly. [District Rule 4703]

23. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

24. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

25. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

26. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

27. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for a period or periods not exceeding three minutes in any one hour. [District Rules 2201 and 4101]

28. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

29. Emission rates from the CTG, except during startup or shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 8.03 lb/hr and 2.5 ppmvd @ 15% O2; SOx (as SO2) – 2.51 lb/hr; PM10 – 6.00 lb/hr; CO – 11.81 lb/hr and 6.0 ppmvd @ 15% O2; or VOC (as methane) – 2.67 lb/hr and 2.0 ppmvd @ 15% O2. NO_X (as NO_2) emission limits are one hour rolling averages. All other pollutant emission concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

30. Ammonia (NH3) emissions shall not exceed either of the following limits: 11.90 lb/hr or 10 ppmvd @ 15% O2 (based on a 24 hour rolling average). [District Rules 2201 and 4102]

31. During periods of startup, CTG exhaust emission rates shall not exceed any of the following limits: NOx (as NO2) – 44.40 lb/hr, SOx – 2.51 lb/hr, PM10 6.00 lb/hr, CO - 106.60 lb/hr, or VOC - 7.60 lb/hr, based on one hour averages. [District Rules 2201]

32. During periods of shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NOx (as NO2) – 34.29 lb/hr, SOx – 2.51 lb/hr, PM10 6.00 lb/hr, CO – 268.57 lb/hr, or VOC - 17.14 lb/hr, based on one hour averages. [District Rules 2201]

33. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

34. The duration of each startup or shutdown shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

35. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

36. Daily emissions from the CTG shall not exceed any of the following limits: NOx (as NO2) – 261.1 lb/day; VOC – 79.1 lb/day; CO – 560.4 lb/day; PM10 – 144.0 lb/day; or SOx (as SO2) - 60.2 lb/day. [District Rule 2201]

37. Quarterly hours of operation shall not exceed any of the following: 1st Quarter - 1,100 hours, 2nd Quarter - 1,100 hours, 3rd Quarter - 1,600 hours, or 4th Quarter - 1,200 hours. [District Rule 2201]

38. Annual emissions from the CTG, calculated on a twelve consecutive month rolling basis, shall not exceed any of the following: NOx (as NO2) - 48,465 lb/year; SOx (as SO2) - 12,550 lb/year; PM10 - 30,000 lb/year; CO - 92,750 lb/year; or VOC - 15,174 lb/year. [District Rule 2201]

39. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

40. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

41. Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = average ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rule 2201]

42. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-7220-1, C-7220-2, C-7220-3, or C-7220-4) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rule 1081]

43. Hazardous Air Pollutant (HAP) emissions shall not exceed 25 tpy all HAPS or 10 tpy any single HAP. [District Rule 4002]

44. Permittee shall conduct an initial speciated HAPS and total VOC source test for one of the GTEs (C-7220-1, '2, '3 or '4), by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. PEC shall correlate the total HAPS emissions rate and the single highest HAP emission rate to the VOC mass emission determined during the speciated HAPs source test. Initial and annual compliance with the HAPS emissions limit (25 tpy all HAPs

or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates for the GTEs (C-7220-1, '2, '3, and '4) determined during initial and annual compliance source testing and the correlation between VOC emissions and HAP(s). [District Rule 4002]

45. Source testing to measure the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 120 days after initial operation and at least once every twelve months thereafter. [District Rules 1081 and 4703 and 40 CFR 60.4400(a)]

46. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) shall be demonstrated within 60 days after the end of the commissioning period and monitored weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

47. The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia – EPA Method 206. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the District prior to the submission of the source test plan. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

48. HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a),(b) and District Rule 4703, 6.4.5]

49. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

50. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]

51. Compliance demonstration (source testing) shall be District witnessed or authorized and samples shall be collected by a certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

52. The turbine shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703 and 40 CFR 60.4335(b)(1)]

53. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703 and 40 CFR 60.4335(b)(1)]

54. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

55. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

56. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

57. The owner/operator shall perform a relative accuracy test audit (RATA) for the NOx, CO, and O2 CEMs as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

58. Results of the CEM system shall be averaged over a one hour period for NOx emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

59. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

60. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other

methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

61. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

62. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

63. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

64. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

65. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

66. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

67. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

68. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing; evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201, and 4703 and 40 CFR 60.8(d)]

69. The permittee shall maintain the following records: quarterly hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

70. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, and 4703]

71. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

72. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

73. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

74. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

75. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

76. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

77. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

78. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

79. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

80. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-7220-5-0:
160 BHP JOHN DEERE MODEL 6068T, OR EQUIVALENT, TIER 2 CERTIFIED DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIREWATER PUMP

1. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Determination of Compliance. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

2. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

3. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Determination of Compliance. [District Rule 2201] N

4. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

5. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

7. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

8. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

9. Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

10. {3403} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]

11. Emissions from this IC engine shall not exceed any of the following limits: 4.5 g-NOx/bhp-hr, 0.6 g-CO/bhp-hr, or 0.4 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

12. Emissions from this IC engine shall not exceed 0.15 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

13. This engine shall be operated only for maintenance, testing, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 52 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

14. The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

15. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

EQUIPMENT DESCRIPTION, UNIT C-7220-6-0:
14,300 GPM INDUCED DRAFT COOLING TOWER SERVED BY A HIGH EFFICIENCY DRIFT ELIMINATOR

1. Permittee shall submit cooling tower design details including the cooling tower type, drift eliminator design details, and materials of construction to the District at least 90 days before the tower is operated. [District Rule 7012]

2. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District NSR Rule]

3. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

5. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

6. No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

7. Drift eliminator drift rate shall not exceed 0.0005%. [District Rule 2201]

8. PM10 emission rate from the cooling tower shall not exceed 8.4 lb/day. [District Rule 2201]

9. Compliance with the PM10 daily emission limit shall demonstrated as follows: PM10 lb/day = circulating water recirculation rate x total dissolved solids concentration in the blowdown water x design drift rate. [District Rule 2201]

10. Compliance with the PM10 emission limit shall be determined by blowdown water sample analysis by independent laboratory within 120 days of initial operation and quarterly thereafter. [District Rule 1081]

11. The permittee shall maintain records of the calculated PM10 emission rate and the laboratory water sample analysis. [District Rule 1070]

12. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

13. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential

development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

14. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

15. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

16. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

17. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

18. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

19. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

20. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

21. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

APPENDIX B
BACT Guidelines

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.7*

Last Update: 10/1/2002

Gas Turbine - = or > 50 MW , Uniform Load, without Heat Recovery

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst, or equal).		
NOx	5.0 ppmvd** @ 15% O2, based on a three-hour average (high temp SCR, or equal).	1. 2.5 ppmvd** @ 15% O2, based on a one-hour average (high temperature Selective Catalytic Reduction (SCR), or equal). 2. 3.0 ppmvd** @ 15% O2, based on a three-hour average (high temp SCR, or equal).	
PM10	Air inlet cooler/filter, lube oil vent coalescer (or equal) and either PUC regulated natural gas, LPG, or non-PUC-regulated gas with < 0.75 grams S/100 dscf.		
SOx	PUC-regulated natural gas, LPG, or Non-PUC-regulated gas with = or < 0.75 grams S/100 dscf.		
VOC	2.0 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst, or equal).	1. 0.6 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst). 2. 1.3 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst, or equal).	

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.4*

Last Update: 6/30/2001

Emergency Diesel I.C. Engine Driving a Fire Pump

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO		Oxidation Catalyst	
NOx	Certified NOx emissions of 6.9 g/bhp-hr or less		
PM10	0.1 grams/bhp-hr (if TBACT is triggered) (corrected 7/16/01) 0.4 grams/bhp-hr (if TBACT is not triggered)		
SOx	Low-sulfur diesel fuel (500 ppmw sulfur or less) or Very Low-sulfur diesel fuel (15 ppmw sulfur or less), where available.		
VOC	Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]	Catalytic Oxidation	

1. Any engine model included in the ARB or EPA diesel engine certification lists and identified as having a PM10 emission rate of 0.149 grams/bhp-hr or less, based on ISO 8178 test procedure, shall be deemed to meet the 0.1 grams/bhp-hr requirement.
2. A site-specific Health Risk Analysis is used to determine if TBACT is triggered. (Clarification added 05/07/01)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

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San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 8.3.10*

Last Update: 6/19/2000

Cooling Tower - Induced Draft, Evaporative Cooling

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
PM10		Cellular Type Drift Eliminator	

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

APPENDIX C
Top Down BACT Analyses

Top Down BACT Analysis for the CTGs

1. BACT Analysis for NO_X Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 3.4.7, 1st quarter 2007, identifies achieved in practice BACT for NO_X emissions from gas turbines = or > 50 MW, Uniform Load, without Heat Recovery as follows:

1) 5.0 ppmvd @ 15% O2, based on a three-hour average (high temp SCR, or equal)

In addition, the SJVUAPCD BACT Clearinghouse guideline 3.4.7, 1st quarter 2007, identifies technologically feasible BACT for NO_X emissions from gas turbines = or > 50 MW, Uniform Load, without Heat Recovery as follows:

1) 2.5 ppmvd @ 15% O2, based on a one-hour average (high temperature Selective Catalytic Reduction (SCR), or equal)
2) 3.0 ppmvd @ 15% O2, based on a three-hour average (high temp SCR, or equal)

No control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) 2.5 ppmvd @ 15% O2, based on a one-hour average (high temperature Selective Catalytic Reduction (SCR), or equal)
2) 3.0 ppmvd @ 15% O2, based on a three-hour average (high temp SCR, or equal)
3) 5.0 ppmvd @ 15% O2, based on a three-hour average (high temp SCR, or equal)

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the highest ranked technologically feasible option. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for NO_X emissions from this gas turbine is 2.5 ppmvd @ 15% O2, based on a one-hour average (high temperature Selective Catalytic Reduction (SCR), or equal). The applicant has proposed to install a gas turbine with NOx emissions of 2.5 ppmvd @ 15% O2 with SCR; therefore BACT for NO_X emissions is satisfied.

2. BACT Analysis for SOx Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 3.4.7, 1st quarter 2007, identifies achieved in practice BACT for SO_X emissions from gas turbines = or > 50 MW, Uniform Load, without Heat Recovery as follows:

1) PUC-regulated natural gas, LPG, or Non-PUC-regulated gas with = or < 0.75 grains S/100 dscf

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

No ranking needs to be done because the applicant has proposed the achieved in practice option.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the only control achieved in practice in the ranking list from Step 3. Therefore, per SJVUAPCD BACT policy, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for SO_X emissions from this gas turbine is PUC-regulated natural gas, LPG, or Non-PUC-regulated gas with = or < 0.75 grains S/100 dscf. The applicant has proposed to install a gas turbine with PUC-regulated natural gas; therefore BACT for SO_X emissions is satisfied.

3. BACT Analysis for PM10 Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 3.4.7, 1st quarter 2007, identifies achieved in practice BACT for PM10 emissions from gas turbines = or > 50 MW, Uniform Load, without Heat Recovery as follows:

1) Air inlet cooler/filter, lube oil vent coalescer (or equal and either PUC regulated natural gas, LPG, or non-PUC-regulated gas with < 0.75 grains S/100 dscf

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

No ranking needs to be done because the applicant has proposed the achieved in practice option.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the only control achieved in practice in the ranking list from Step 3. Therefore, per SJVUAPCD BACT policy, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for PM10 emissions from this gas turbine is air inlet cooler/filter, lube oil vent coalescer (or equal and either PUC regulated natural gas, LPG, or non-PUC-regulated gas with < 0.75 grains S/100 dscf. The applicant has proposed to install a gas turbine with an air inlet filter and lube oil vent coalescer and use of PUC regulated natural gas; therefore BACT for PM10 emissions is satisfied.

4. BACT Analysis for CO Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 3.4.7, 1st quarter 2007, identifies achieved in practice BACT for CO emissions from gas turbines = or > 50 MW, Uniform Load, without Heat Recovery as follows:

1) 6.0 ppmvd @ 15% O2, based on a three-hour average (oxidation catalyst, or equal)

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

No ranking needs to be done because the applicant has proposed the achieved in practice option.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the only control achieved in practice in the ranking list from Step 3. Therefore, per SJVUAPCD BACT policy, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for CO emissions from this gas turbine is 6.0 ppmvd @ 15% O2, based on a three-hour average (oxidation catalyst, or equal). The applicant has proposed to install a gas turbine with CO emissions of 6.0 ppmvd @ 15% O2, based on a three-hour average (oxidation catalyst, or equal); therefore BACT for CO emissions is satisfied.

5. BACT Analysis for VOC Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 3.4.7, 1st quarter 2007, identifies achieved in practice BACT for VOC emissions from gas turbines = or > 50 MW, Uniform Load, without Heat Recovery as follows:

1) 2.0 ppmvd @ 15% O2, based on a three-hour average (oxidation catalyst, or equal)

In addition, the SJVUAPCD BACT Clearinghouse guideline 3.4.7, 1st quarter 2007, identifies technologically feasible BACT for VOC emissions from gas turbines = or > 50 MW, Uniform Load, without Heat Recovery as follows:

2) 0.6 ppmvd @ 15% O2, based on a three-hour average (oxidation catalyst)
3) 1.3 ppmvd @ 15% O2, based on a three-hour average (oxidation catalyst, or equal)

No control alternatives identified as alternate basic equipment for this class and category of source are listed.

Although not specifically listed on BACT Guideline 3.4.7, a SCONOx system is a technically feasible control technology capable of achieving VOC emissions of 0.6 ppmvd @ 15% O2 and will be examined for cost effectiveness.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1a)0.6 ppmvd @ 15% O2, based on a three-hour average (SCONOx)
1b)0.6 ppmvd @ 15% O2, based on a three-hour average (oxidation catalyst)
2) 1.3 ppmvd @ 15% O2, based on a three-hour average (oxidation catalyst, or equal)
3) 2.0 ppmvd @ 15% O2, based on a three-hour average (oxidation catalyst, or equal)

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

Per District practice in previous power plant projects, a SCONOx system and the installation of a bigger oxidation catalyst or additional catalyst material to the existing oxidation catalyst are the only two feasible control alternatives capable of achieving a minimum control efficiency of at least 90% for VOC emissions. Therefore, a cost analysis will be performed for each of these control technologies.

1a. SCONOx System - 0.6 ppmvd @ 15% O_2, based on three-hour average

SCONOx systems typically result in reductions of NO_X, CO and VOC emissions. For control technologies that control more than one type of air pollutant, a multi-pollutant cost effectiveness threshold (MCET) must be calculated. If the total annual cost of the control technology is greater than the MCET, the control technology or equipment under review cannot be required as BACT (Per District policy APR 1305).

As stated in Section VIII (Rule 2201) of this document, BACT is required for NO_x, SO_x, PM_{10}, CO, and VOC and emissions for each CTG. As stated above, $SCONO_x$ typically results in reductions of NO_x, CO and VOC emissions. The MCET for this operation can be calculated using the following formula:

$$MCET (\$/yr) = (E_{NOx} * T_{NOx}) + (E_{CO} * T_{CO}) + (E_{VOC} * T_{VOC})$$

Where: E_{NOx} = tons-NO_x controlled/yr
E_{CO} = tons-CO controlled/yr
E_{VOC} = tons-VOC controlled/yr
T_{NOx} = District's cost effectiveness threshold for NO_x (\$9,700/ton-NO_x)
T_{CO} = District's cost effectiveness threshold for CO (\$300/ton-CO)
T_{VOC} = District's cost effectiveness threshold for VOC (\$5,000/ton-VOC)

A. MCET

Uncontrolled emissions from a simple cycle turbine will be considered as the emissions generated from an operation using industry standard materials with no control devices.

NO_X Emissions:

Industry Standard

Per applicant, the turbine uncontrolled NOx emissions is 89.90 lb/hr (28 ppmvd @ 15% O2) which will be taken as industry standard.

The applicant is proposing to operate each of these turbines for up to 5,000 hours per year. Based on an industry standard of NO_X emission rate of 89.90 lb/hr, the total, uncontrolled annual NO_X emissions are:

Uncontrolled NO_X Emissions, Per Turbine = 89.90 lb/hr x 5,000 hr/year
Uncontrolled NO_X Emissions, Per Turbine = 449,500 lb/year

2.5 ppmvd NOx @ 15% O2

Controlled NO_X Emissions, Per Turbine = 8.03 lb/hr x 5,000 hr/year
Controlled NO_X Emissions, Per Turbine = 40,150 lb/year

Therefore, the amount of NO_X emissions controlled by a SCONOx system can be calculated as follows:

E_{NOx} = Uncontrolled NO_X Emissions (lb/year) – Controlled NO_X Emissions (lb/year)
E_{NOx} = 449,500 lb/year – 40,150 lb/year

E_{NOx} = 409,350 lb/year (204.7 tons/year)

CO Emissions:

Industry Standard

CO emission factor is 3.0E-02 lb/MMBtu taken from AP-42 Table 3.1-1 (4/00) with water-steam injection.

The applicant is proposing to operate each of these turbines for up to 5,000 hours per year. Based on an industry standard of CO emission rate of 3.0E-02 lb/MMBtu and the maximum combustor rating of each turbine, the total, uncontrolled annual CO emissions are:

Uncontrolled CO Emissions, Per Turbine = 3.0E-02 lb/MMBtu x 909.7 MMBtu/hr 5,000 hr/year
Uncontrolled CO Emissions, Per Turbine = 136,455 lb/year

6.0 ppmvd CO @ 15% O2

Controlled CO Emissions, Per Turbine = 11.81 lb/hr x 5,000 hr/year
Controlled CO Emissions, Per Turbine = 59,050 lb/year

Therefore, the amount of CO emissions controlled by a SCONOx system can be calculated as follows:

E_{CO} = Uncontrolled CO Emissions (lb/year) – Controlled CO Emissions (lb/year)
E_{CO} = 136,455 lb/year – 59,050 lb/year

E_{CO} = 77,405 lb/year (38.7 tons/year)

VOC Emissions:

Industry Standard

Per applicant, the turbine uncontrolled VOC emissions is 6.70 lb/hr (4-7 ppmvd @ 15% O2) which will be taken as industry standard.

The applicant is proposing to operate each of these turbines for up to 5,000 hours per year. Based on an industry standard of VOC emission rate of 6.70 lb/hr, the total, uncontrolled annual VOC emissions are:

Uncontrolled VOC Emissions, Per Turbine = 6.70 x 5,000 hr/year
Uncontrolled VOC Emissions, Per Turbine = 33,500 lb/year

0.6 ppmvd VOC @ 15% O2

Taking the ratio of the proposed value of 2.20 lb/hr @ 2.0 ppmvd,

x / 0.6 ppmv = 2.2 lb/hr / 2ppmv

x = 0.66 lb/hr

Controlled VOC Emissions, Per Turbine = 0.66 lb/hr x 5,000 hr/year
Controlled VOC Emissions, Per Turbine = 3,300 lb/year

Therefore, the amount of VOC emissions controlled by a SCONOx system can be calculated as follows:

E_{VOC} = Uncontrolled VOC Emissions (lb/year) – Controlled VOC Emissions (lb/year)
E_{VOC} = 33,500 lb/year – 3,300 lb/year

E_{VOC} = 30,200 lb/year (15.1 tons/year)

Using these values, the MCET for a SCONOx system for the purposes of this project is as follows:

MCET ($/yr) = ($E_{NOx}$ * T_{NOx}) + (E_{CO} * T_{CO}) + (E_{VOC} * T_{VOC})
MCET ($/yr) = (204.7 ton/year * $9,700/ton) + (38.7 ton/year * $300/ton) + (15.1 ton/year * $5,000/ton)

MCET = $2,072,700/year

B. SCONOx Capital Cost

The District conducted research to determine the cost of installing a $SCONO_X$ system. Mr. James Whitehorn at EmeraChem and provided a scope of the turbine installation project and the cost to install a $SCONO_X$ system. Mr. Whitehorn stated that a system for a 100 MW, 909.7 MMBtu/hr LM-100 turbine would cost approximately $4 million.

Description of Cost	Cost Factor	Cost	Source
Direct Capital Costs (DC):			
Purchase Equipment Costs (PE):			
(A) Basic Equipment: $SCONO_x$ System		4,000,000	**EmeraChem**
(B) Instrumentation: included in base price		0	**OAQPS**
PE Total:		4,000,000	
Direct Installation Costs (DI):			
Foundation and Supports:	0.08 PE	320,000	**OAQPS**
Handling and Erection:	0.14 PE	560,000	**OAQPS**
Electrical:	0.04 PE	160,000	**OAQPS**
Piping:	0.02 PE	80,000	**OAQPS**
Insulation:	0.01 PE	40,000	**OAQPS**
Painting:	0.01 PE	40,000	**OAQPS**
DI Total:		1,200,000	
Site Preparation and Buildings			
DC Total = PE + DI:		5,200,000	
Indirect Costs (IC):			
Engineering:	0.10 PE	400,000	**OAQPS**
Construction and Field Expenses:	0.05 PE	200,000	**OAQPS**
Contractor Fees:	0.10 PE	400,000	**OAQPS**
Start-up:	0.02 PE	80,000	**OAQPS**
Performance Testing:	0.01 PE	40,000	**OAQPS**
Contingencies:	0.03 PE	120,000	**OAQPS**
IC Total:		1,339,200	
Total Capital Investments (TCI = DC + IC):		6,440,000	

Pursuant to the District BACT Policy section X. (Revised 4/18/95), the annual cost of installing and maintaining the SCONOx system will be calculated as follows. The installation cost will be spread over the expected life of the SCONOx system which is estimated at 10 years and using the capital recovery equation (Equation 1). A 10% interest rate is assumed in the equation and the assumption will be made that the equation has no salvage value at the end of the ten-year cycle.

Equation 1: $A = [P * i(I+1)^n]/[(I+1)^n-1]$

Where:

A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$A = [\$6,440,000 * 0.1 * (1.1)^{10}]/[(1.1)^{10}-1]$
= $1,048,080/year

B. SCONOx Operation and Maintenance Costs

The values in the following table were taken from the application review performed for project C-1020647.

Direct Annual Costs (DAC): Assume $SCONO_X$ requires 0.5 hrs/shift			
Operating Costs (O): 3 shifts per 24 hr/day; 5,000 hours/year (≈ 625 shifts/year)			
Operator: 0.50 hr/shift	$25/hr	7,813	**OAQPS**
Supervisor:	15% operator	1,172	**OAQPS**
Maintenance Costs (M):			
Labor: 0.5 hr/shift	$25/hr	7,813	**OAQPS**
Material:	100% labor	7,813	**OAQPS**
Utility Costs (U):			
Performance loss:	0.6%		
Electricity Cost (taken from project C-1020647, 49.6 MW Power Plant):	$0.08/kWh	180,096	**Variable per EmeraChem**
Catalyst Replace:		374,054	**EmeraChem**
Catalyst Washing:	Variable	36,000	**EmeraChem**
Catalyst Dispose: (Precious Metal Recovery = 1/3 replace cost)		-124,685	**EmeraChem**
H_2 carrier stream: 93 lb steam/hr/MW (@ $0.008/lb)	Variable	279,149	**EmeraChem**
H_2 reforming: 14 ft^3 CH_4/hr/MW (@ $0.004/$ft^3$)	Variable	21,011	**EmeraChem**
Total DAC:		790,236	
Indirect Annual Costs (IAC):			
Overhead:	60% O & M	14,767	**OAQPS**
Administrative:	0.02 TCI	128,800	**OAQPS**
Insurance:	0.01 TCI	64,400	**OAQPS**
Property Tax:	0.01 TCI	64,400	**OAQPS**
Total IAC:		272,367	
Total Operation and Maintenance Cost (DAC + IAC):		**1,062,603**	

C. SCONOx Total Cost

Total Annual Cost = Annualized Capital Cost + Annual Operation and Maintenance Cost
= $1,040,080 + $1,062,603
= $2,102,683/year

Since the annual cost ($2,102,683) is greater than the MCET ($2,072,700), a SCONOx system achieving 0.6 ppmvd VOC @ 15% O2 is not cost effective.

1b. Oxidation Catalyst - 0.6 ppmvd @ 15% O2, based on a three-hour average

Capital costs are estimated by the SCR supplier, Deltak.

Capital cost for oxidation catalyst (uncontrolled to 2.0 ppmvd VOC @ 15% O2)
= $350,000 per turbine

Capital cost for additional catalyst (2.0 ppmvd to 0.6 ppmvd VOC @ 15% O2)
= $350,000 per turbine

Total capital cost = $350,000 + $350,000 = $700,000

Total annual cost = $\$700{,}000\left[\dfrac{0.1(1.1)^{10}}{(1.1)^{10}-1}\right]$ = $113,922/yr

For cost analysis purposes, only steady state operation emissions are included. It is assumed the full 5,000 hours per year operation is at steady state.

Industry Standard

Per applicant, the turbine uncontrolled VOC emissions is 6.70 lb/hr (4-7 ppmvd @ 15% O2).

CO emission factor is 3.0E-02 lb/MMBtu taken from AP-42 Table 3.1-1 (4/00) with water-steam injection.

3.0E-02 lb-CO/MMBtu x 909.7 MMBtu/hr = 27.29 lb-CO/hr

$VOC_{\text{industry standard}}$ = 6.70 lb/hr
$CO_{\text{industry standard}}$ = 3.0E-02 lb/MMBtu x 909.7 MMBtu/hr = 27.29 lb/hr

0.6 ppmvd VOC @ 15% O2, based on a three-hour average (oxidation catalyst)

VOC reductions = (6.70 - 2.20 lb/hr) x 5000 hr/yr x ton/2000 lb = 11.25 tons/yr

6.0 ppmvd CO @ 15% O2, based on a three-hour average (oxidation catalyst)

CO reductions = (27.29 – 11.81 lb/hr) x 5000 hr/yr x ton/2000 lb = 38.7 tons/yr

District BACT policy requires the use of a Multi-Pollutant Cost Effectiveness Threshold (MCET) for a BACT option controlling more than one pollutant. The installation of an oxidation catalyst will control CO and VOC emissions. The MCET is calculated as follows:

MCET ($/yr) = $(E_{VOC} \times T_{VOC}) + (E_{CO} \times T_{CO})$

Where: E_{VOC} = tons-VOC controlled/yr
E_{CO} = tons-CO controlled/yr
T_{VOC} = District's cost effectiveness threshold for VOC ($5,000/ton)
T_{CO} = District's cost effectiveness threshold for CO ($300/ton)

MCET ($/yr) = ($E_{VOC}$ x T_{VOC}) + (E_{CO} x T_{CO})
= (11.25 x $5000) + (38.7 x $300)
= $67,860/yr

Since the annual cost ($113,922) is greater than the MCET ($67,860), an oxidation catalyst achieving 0.6 ppmvd VOC @ 15% O2 is not cost effective.

2. Oxidation Catalyst - 1.3 ppmvd @ 15% O2, based on a three-hour average

Since the capital cost for an oxidation catalyst system to achieve a VOC emission concentration of 1.3 ppmvd @ 15% O2 is only slightly lower than a 0.6 ppmvd @ 15% O2 system, it is assumed that if a 0.6 ppmvd system is not cost effective, then a 1.3 ppmvd system will also not be cost effective because of lower VOC emission reductions.

e. Step 5 - Select BACT

BACT for VOC emissions from this gas turbine is 2.0 ppmvd @ 15% O2, based on a three-hour average (oxidation catalyst, or equal). The applicant has proposed to install a gas turbine with VOC emissions of 2.0 ppmvd @ 15% O2; therefore BACT for VOC emissions is satisfied.

Top Down BACT Analysis for the Emergency IC Engine

Oxides of nitrogen (NO_X) are generated from the high temperature combustion of the diesel fuel. A majority of the NO_X emissions are formed from the high temperature reaction of nitrogen and oxygen in the inlet air. The rest of the NO_X emissions are formed from the reaction of fuel-bound nitrogen with oxygen in the inlet air.

1. BACT Analysis for NO_X Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 3.1.4, 1st quarter 2007, identifies achieved in practice BACT for NO_X emissions from emergency diesel IC engines powering a firewater pump as follows:

1) Certified emissions of 6.9 g-NO_X/bhp-hr or less

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

No ranking needs to be done because the applicant has proposed the achieved in practice option.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the only control achieved in practice in the ranking list from Step 3. Therefore, per SJVUAPCD BACT policy, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for NO_X emissions from this emergency diesel IC engine powering a firewater pump is having certified emissions of 6.9 g-NO_X/bhp-hr or less. The applicant has proposed to install a 160 bhp emergency diesel IC engine powering a firewater pump with certified emissions of 6.9 g-NO_X/bhp-hr or less; therefore BACT for NO_X emissions is satisfied.

2. BACT Analysis for CO Emissions:

Carbon monoxide (CO) emissions are generated from the incomplete oxidation of carbon.

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 3.1.4, 1st quarter 2007, identifies no control technology as achieved in practice BACT for CO emissions from emergency diesel IC engines powering a firewater pump.

In addition, the SJVUAPCD BACT Clearinghouse guideline 3.1.4, 1st quarter 2007, identifies technologically feasible BACT for CO emissions from emergency diesel IC engines powering a firewater pump as follows:

1) An oxidation catalyst

No control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) An oxidation catalyst

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

However, this engine has been UL Certified, and the UL certification does not include an oxidation catalyst, and the addition of an oxidation catalyst would void the UL certification, which is required for firewater pump engines. Therefore, the oxidation catalyst option will not be required.

e. Step 5 - Select BACT

BACT for CO emissions from this emergency diesel IC engine powering a firewater pump is having no control technology for CO emissions. The applicant has proposed to install a 160 bhp emergency diesel IC engine powering a firewater pump with no control technology for CO emissions; therefore BACT for CO emissions is satisfied.

3. BACT Analysis for VOC Emissions:

Volatile organic compounds (VOC) are emitted from the crankcase of the engine as a result of piston ring blow-by.

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 3.1.4, 1st quarter 2007, identifies achieved in practice BACT for VOC emissions from emergency diesel IC engines powering a firewater pump as follows:

1) Positive crankcase ventilation (unless it voids the Underwriters Laboratories (UL) certification)

In addition, the SJVUAPCD BACT Clearinghouse guideline 3.1.4, 1st quarter 2007, identifies technologically feasible BACT for VOC emissions from emergency diesel IC engines powering a firewater pump as follows:

1) Catalytic oxidation

No control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1)Catalytic oxidation
2)Positive crankcase ventilation (unless it voids the Underwriters Laboratories (UL) certification)

d. Step 4 - Cost effectiveness analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

However, this engine has been UL Certified, and the UL certification does not include a catalytic oxidation system or a positive crankcase ventilation system, and the addition of a catalytic oxidation system or a positive crankcase ventilation system would void the UL certification, which is required for firewater pump engines. Therefore, both the catalytic oxidation system and the positive crankcase ventilation system options will not be required.

e. Step 5 - Select BACT

BACT for VOC emissions from this emergency diesel IC engine powering a firewater pump is having no control technology for VOC emissions. The applicant has proposed to install a 160 bhp emergency diesel IC engine powering a firewater pump with no control technology for VOC emissions; therefore BACT for VOC emissions is satisfied.

Top Down BACT Analysis for the Cooling Tower

1. BACT Analysis for PM10 Emissions:

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 8.3.10, 1st quarter 2007, identifies achieved in practice BACT for PM10 emissions from cooling towers – induced draft, evaporative cooling as follows:

1) Cellular Type Drift Eliminator

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

No ranking needs to be done because the applicant has proposed the achieved in practice option.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the only control achieved in practice in the ranking list from Step 3. Therefore, per SJVUAPCD BACT policy, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for PM10 emissions from this cooling tower is cellular type drift eliminator. The applicant has proposed to install a cellular type drift eliminator with a drift rate of 0.0005%; therefore BACT for PM10 emissions is satisfied.

APPENDIX D
Interpollutant Offset Analysis

SOx for PM10 Interpollutant Offset Analysis
Panoche Energy Center Power Plant

Facility Name:	Panoche Energy Center LLC	Engineer:	Stanley Tom
Mailing Address:	63 Kendrick St Needham, MA 02494	Date:	March 7, 2007
Contact Person:	Gary R. Chandler	Lead Engineer:	Joven Refuerzo
Telephone:	(801) 253-1278		
Application #:	C-7220-1-0 through '6-0		
Project #:	C-1062518		
Location:	W Panoche Rd, Firebaugh, CA		
Complete:	October 18, 2006		

I. Proposal

Panoche Energy Center LLC (PEC) is seeking approval from the San Joaquin Valley Air Pollution Control District for the installation of an electrical power generation facility. Panoche will be a simple-cycle power generation facility consisting of four General Electric LMS100 natural gas-fired combustion turbine generators (CTGs), each equipped with water injection to the combustors, a selective catalytic reduction (SCR) system with 19 percent aqueous ammonia injection, and an oxidation catalyst. The total net generating capacity will be approximately 400 megawatts (MW).

PEC is proposing to install a 160 bhp diesel-fired emergency internal combustion (IC) engine powering a firewater pump and a 27,600 gallon per minute cooling tower.

PEC is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

Facility C-7220 will become a major source for NOx, CO, and VOC. There will be an increase in emissions for all pollutants and offsets are required for NOx, PM10, and VOC.

II. Applicable Rules

Rule 2201 New and Modified Stationary Source Review Rule (9/21/06)
(Section 3.30 and 4.13.3.2)

III. Process Description

The GE LMS100 is an inter-cooled gas turbine system developed especially for the power generation industry utilizing heavy-duty gas turbine and aero-derivative gas turbine technology. The LMS100 produces approximately 100 MW at an efficiency that is 10 percent higher than other commercial simple-cycle turbines. The LMS100 is specifically designed for cyclic applications providing flexible power and 10 minute starts.

Electricity generated by PEC will be delivered to the existing Pacific Gas and Electric (PG&E) electrical transmission system at the adjacent Panoche Substation. Interconnection at this substation will minimize impacts to the PG&E transmission system while providing efficient peaking power for use during peak demand.

Auxiliary equipment will include inlet air filters with evaporative coolers, turbine compressor section inter-cooler, mechanical draft cooling tower, circulating water pumps, water treatment equipment, natural gas compressors, generator step-up and auxiliary transformers, and water storage tanks.

A CTGs power output is defined by its capacity factor. The capacity factor average the engine's output and divides that by the engine's rated output for a typical day. Each CTG will generate 100 MW net at summer design ambient conditions. The project will have an annual capacity factor of approximately 57 percent, depending on dispatch to meet annual demand.

Electric power generated at the PEC facility will be sold to PG&E under a 20-year power purchase agreement (PPA) between PEC and PG&E. Design of the plant and equipment selection is based on requirements in the PPA.

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record fuel gas flow rate, NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG. This system will generate reports of emission data in accordance with permit requirements and will send alarm signals to the plant's control system when emissions approach or exceed pre-selected limits.

The emergency engine powers a firewater pump. Other than emergency operation, the engine may be operated up to 52 hours per year for maintenance and testing purposes.

IV. Equipment Listing

C-7220-1-0: 100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST

C-7220-2-0: 100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST

C-7220-3-0: 100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #3 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST

C-7220-4-0: 100 MW SIMPLE-CYCLE POWER GENERATING SYSTEM #4 CONSISTING OF A GENERAL ELECTRIC LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND AN OXIDATION CATALYST

C-7220-5-0: 160 BHP JOHN DEERE MODEL 6068T, OR EQUIVALENT, TIER 2 CERTIFIED DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIREWATER PUMP

C-7220-6-0: 27,600 GPM COOLING TOWER WITH 5 CELLS AND DRIFT ELIMINATOR

V. Interpollutant Offset Ratio Proposal SOx for PM10

Rule 2201, New and Modified Stationary Source Review, specifically allows the use of PM-10 precursor ERCs to offset PM-10 increases:

> *4.13.3 Interpollutant offsets may be approved by the APCO on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, that the emission increases from the new or modified source will not cause or contribute to a violation of an Ambient Air Quality Standard. In such cases, the APCO shall, based on an air quality analysis, impose offset ratios equal to or greater than the requirements of this rule.*
>
> *4.13.3.2 Interpollutant offsets between PM10 and PM10 precursors may be allowed.*

Based on this language, an applicant must demonstrate an appropriate interpollutant offset ratio, based on an air quality analysis (that is, based on the science of the precursor-to-PM10 relationship given the atmospheric chemistry and the meteorology of the locale).

Per submittal, the applicant has demonstrated the SOx-to-PM10 precursor relationship for this location, and proposes an appropriate interpollutant ratio, such that the applicant has demonstrated that their SOx reduction package has greater PM10 reduction as if PM10 offsets were used.

The applicant has proposed to offset the increases in PM10 emissions associated with this project by using SOx ERCs. Per submittal, the applicant has demonstrated the SOx to PM10 precursor relationship for this location. Based on that relationship and the submitted analysis, PEC proposed a SOx for PM10 interpollutant ratio of 1.8:1 (see Attachment 1).

The District performed an analysis via a chemical mass balance model using Fresno County modeling data. Fresno County modeling data is valid for all projects in the Fresno or Madera County regions. The SOx for PM10 interpollutant ratio of 1.867:1 was established by the District via a chemical mass balance model similar to an analysis performed for the San Joaquin Valley Energy Partners project (see Attachment 2). Upon review of the District's analysis, the applicant has agreed to the use of the above interpollutant offset ratio for this project. The originating location of reduction of the proposed ERC certificates are greater than 15 miles from the proposed project. Therefore, a distance offset ratio of 1.5 applies. Combining the interpollutant and distance offset ratio, an overall SOx for PM10 offset ratio of 1.867 x 1.5 = 2.8:1 is valid for project S-1062518.

VI. Project Offset Calculations

The following shows the offset requirements and calculations for PM10.

Annual Potential to Emit (Each of C-7220-1-0 through '4-0)	
	Annual Emissions Limitation (lb/year) (per CTG)
NO_X	48,465
SO_X	12,550
PM_{10}	30,000
CO	92,750
VOC	15,174
NH_3	35,700

Annual Potential to Emit (C-7220-5-0	
	Annual Emissions Limitation (lb/year) (IC Engine)
NO_X	83
SO_X	0
PM_{10}	3
CO	11
VOC	7

C-7220-6-0 (Cooling Tower)

The applicant has proposed that the maximum water flowrate through the cooling tower is 27,600 gallons per minute. Therefore, the PM_{10} emissions from the cooling tower can be estimated using the emission factor listed above and the water flowrate.

Daily PM_{10} PE = Drift rate x TDS (lb/gallon) x water throughput (gal/min) x 60 min/hr x 24 hr/day
Daily PM_{10} PE = 0.000005 x 14.19 lb/1000 gallon x 27,600 gal/min x 60 min/hr x 24 hr/day
= 2.8 lb/day/cycle

There are three cycles of concentration for the cooling tower.

Daily PM_{10} PE = 2.8 lb/day/cycle x 3 cycles
= 8.4 lb/day

Daily PM_{10} PE = 8.4 lb/day

Annual PM_{10} PE = 0.000005 x 14.19 lb/1000 gallon x 27,600 gal/min x 60 min/hr x 5000 hr/yr x 3 cycles
= 1,762 lb/yr

Annual PM_{10} PE = 1,762 lb/yr

Post Project Stationary Source Potential to Emit [SSPE2] (lb/year)					
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC
C-7220-1-0	48,465	12,550	30,000	92,750	15,174
C-7220-2-0	48,465	12,550	30,000	92,750	15,174
C-7220-3-0	48,465	12,550	30,000	92,750	15,174
C-7220-4-0	48,465	12,550	30,000	92,750	15,174
C-7220-5-0	83	0	3	11	7
C-7220-6-0	0	0	1,762	0	0
Post Project SSPE (SSPE2)	193,943	50,200	121,765	371,011	60,703

PM10

SSPE2 (PM_{10}) = 121,765 lb/year
C-7220-5-0 (PM_{10}) = 3 lb/year
Offset threshold (PM_{10}) = 29,200 lb/year
ICCE = 0 lb/year

Offsets Required (lb/year) = [(121,765 – 3 – 29,200 + 0) x DOR]
= 92,562 x DOR

The applicant has proposed the following quarterly hours of operation:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
1,100 hr	1,100 hr	1,600 hr	1,200 hr

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr without distance ratio):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
20,364	20,364	29,620	22,215

The applicant is proposing to use ERC Certificates S-2209-4, S-2210-4, S-2211-4, S-2212-4, S-2213-4, S-2227-4, N-74-5, N-268-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, an offset ratio of 1.5:1 is applicable and the amount of PM10 ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 92,562 x 1.5
= 138,843 lb PM10/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
30,545	30,545	44,430	33,322

The applicant has stated that the facility plans to use ERC certificates S-2209-4, S-2210-4, S-2211-4, S-2212-4, S-2213-4, S-2227-4, N-74-5, N-268-5 to offset the increases in PM10 emissions associated with this project. The above certificates have available quarterly credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #S-2431-4	8,741	7,519	8,213	8,457
ERC #S-2432-4	904	923	981	961
ERC #S-2433-4	3,587	3,857	4,416	4,220
ERC #S-2434-4	3,382	3,622	3,173	3,855
ERC #S-2436-4	0	686	802	723
ERC #S-2435-4	0	1,079	1,058	951
ERC #N-559-5	1,560	1,560	1,560	1,560
ERC #N-591-5	53,530	49,310	0	91,616

Project PM10 offset requirements

The applicant states PM10 and SOx ERC certificates S-2209-4, S-2210-4, S-2211-4, S-2212-4, S-2213-4, S-2227-4, N-74-5, N-268-5 will be utilized to supply the PM10 offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM10 Emissions to be offset: (at a 1.5:1 ratio):	30,545	30,545	44,430	33,322
Available ERCs from certificate S-2431-4:	8,741	7,519	8,213	8,457
ERCs applied from certificate S-2431-4 fully withdrawn as certificate S-2431-4:	-8,741	-7,519	-8,213	-8,457
Remaining ERCs from certificate S-2431-4:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio):	21,804	23,026	36,217	24,865

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 ratio):	21,804	23,026	36,217	24,865
Available ERCs from certificate S-2432-4:	904	923	981	961
ERCs applied from certificate S-2432-4 fully withdrawn as certificate S-2432-4:	-904	-923	-981	-961
Remaining ERCs from certificate S-2432-4:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio):	20,900	22,103	35,236	23,904

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 ratio):	20,900	22,103	35,236	23,904
Available ERCs from certificate S-2433-4:	3,587	3,857	4,416	4,220
ERCs applied from certificate S-2433-4 fully withdrawn as certificate S-2433-4:	-3,587	-3,857	-4,416	-4,220
Remaining ERCs from certificate S-2433-4:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio):	17,313	18,246	30,820	19,684

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 ratio):	17,313	18,246	30,820	19,684
Available ERCs from certificate S-2434-4:	3,382	3,622	3,173	3,855
ERCs applied from certificate S-2434-4 fully withdrawn as certificate S-2434-4:	-3,382	-3,622	-3,173	-3,855
Remaining ERCs from certificate S-2434-4:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio):	13,931	14,624	27,647	15,829

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 ratio):	13,931	14,624	27,647	15,829
Available ERCs from certificate S-2436-4:	0	686	802	723
ERCs applied from certificate S-2436-4 fully withdrawn as certificate S-2436-4:	0	-686	-802	-723
Remaining ERCs from certificate S-2436-4:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio):	13,931	13,938	26,845	15,106

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 ratio):	13,931	13,938	26,845	15,106
Available ERCs from certificate S-2435-4:	0	1,079	1,058	951
ERCs applied from certificate S-2435-4 fully withdrawn as certificate S-2435-4:	0	-1,079	-1,058	-951
Remaining ERCs from certificate S-2435-4:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio):	13,931	12,859	25,787	14,155

As seen above, the facility is lacking sufficient credits to fully offset the emissions increases for PM10.

As proposed by the applicant, in order to satisfy District offset requirements the applicant has proposed providing SOx reductions in place of PM10 reductions. District Rule 2201 Section 4.13.3 allows such interpollutant substitutions provided the applicant shows that the substitution will not cause or contribute to the violation of an ambient air quality standard and that the appropriate interpollutant offset ratio is utilized.

The applicant has stated that the facility plans to use ERC certificates N-559-5 and N-591-5 to offset the increases in PM10 emissions associated with this project. The above certificates have available quarterly credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #N-559-5	1,560	1,560	1,560	1,560
ERC #N-591-5	53,530	49,310	0	91,616
Total	55,090	50,870	1,560	93,176

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM10 and PM10 precursors (i.e. SOx) may be allowed. The applicant is proposing to use interpollutant offsets SOx for PM10 at an interpollutant ratio of 1.867:1 (see Attachment 1).

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.867 = 2.80).

Project SOx for PM10 offset requirements

The applicant states SOx ERC certificates N-559-5 and N-591-5 will be utilized to supply the PM10 offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 ratio):	13,931	12,859	25,787	14,155
Remaining PM10 emissions to be offset with SOx ERCs (at a 1.5:1 distance ratio and a 1.867:1 interpollutant SOx:PM10 ratio):	26,009	24,008	48,144	26,427
Available ERCs from certificate N-559-5:	1,560	1,560	1,560	1,560
ERCs applied from certificate N-559-5 fully withdrawn as certificate N-559-5:	-1,560	-1,560	-1,560	-1,560
Remaining ERCs from certificate N-559-5:	0	0	0	0
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.867:1 interpollutant SOx:PM10 ratio):	24,449	22,448	46,584	24,867

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 emissions to be offset with SOx ERCs (at a 1.5:1 distance ratio and a 1.867:1 interpollutant SOx:PM10 ratio):	24,449	22,448	46,584	24,867
Available ERCs from certificate N-591-5:	53,530	49,310	0	91,616
ERCs applied from certificate N-591-5 partially withdrawn:	-24,449	-22,448	0	-24,867
Remaining ERCs from certificate N-591-5:	29,081	26,862	0	66,749
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.867:1 interpollutant SOx:PM10 ratio):	0	0	46,584	0

Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SOx ERCs are being used to offset PM10 emissions, the above applies to the SOx ERCs.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 emissions to be offset with SOx ERCs (at a 1.5:1 distance ratio and a 1.867:1 interpollutant SOx:PM10 ratio):	0	0	46,584	0
Remaining ERCs from certificate N-591-5:	29,081	26,862	0	66,749
4th qtr. ERCs applied to 3rd qtr. ERCs:	0	0	46,584	← -46,584
Remaining ERCs from certificate N-591-5:	29,081	26,862	46,584	20,165
ERCs applied from certificate N-591-5 partially withdrawn:	0	0	-46,584	0
Remaining ERCs from certificate N-591-5:	29,081	26,862	0	20,165
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.867:1 interpollutant SOx:PM10 ratio):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly PM10 emissions increases associated with this project.

VII. Conclusion

Approve use of an overall SOx for PM10 interpollutant offset ratio of 2.8:1 (1.867 x 1.5).

VIII. Recommendation

Compliance with all applicable rules and regulations is expected. Issue Authorities to Construct C-7220-1-0 through '6-0 with a SOx for PM10 interpollutant offset ratio of 1.867:1.

Attachment

1: Applicant Interpollutant Offset Ratio Proposal Justification
2: District Review and Approval

Attachment 1

Applicant Interpollutant Offset Ratio Proposal Justification

Bakersfield Big West Refinery
PM10 Interpollutant Offset Ratio Analysis

	Notes	Units	Estimate	Uncertainty
PM10				
"Vegetative Burning" Total	1	μg/m^3	7.50	2.43
Industry Component (30%)	2	μg/m^3	2.25	
Regional Background (20%)	3	μg/m^3	0.45	
Industry minus Background		μg/m^3	1.80	
County Contribution	4	μg/m^3	0.90	
Organic Carbon PM10 Inventory - Kern Cou	5	ton/day	5.63	
County Impact		μg/m^3 per ton	0.16	0.21
Sulfate				
Ammonium Sulfate	6	μg/m^3	2.60	0.29
Regional Background	7	μg/m^3	1.00	
Ammonium Sulfate minus Background		μg/m^3	1.60	
County Contribution	8	μg/m^3	0.80	
SOx Inventory - Kern County	9	ton/day	9.08	
County Impact		μg/m^3 per ton	0.09	0.10
Tons of SOx to Equal Effect of 1 ton PM10	10		1.81	2.16

1. Per SJVUAPCD and CARB, PM10 emissions from stationary industrial combustion sources a in the Vegetative Burning category from Chemical Mass Balance modeling performed for the S 2003 PM10 Attainment Plan (Bakersfield - Golden State monitoring station).
2. Per SJVUAPCD, 30% of this category is attributed to stationary industrial combustion sources
3. Per SJVUAPCD, regional background is estimated to be 20% of net concentration after previo adjustment to Vegetative Burning category.
4. Contribution from sources within Kern County is 50% of net concentration after previous adjustments to Vegetative Burning category.
5. Organic carbon PM10 inventory for Kern County that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
6. Ammonium sulfate category from Chemical Mass Balance modeling performed for the SJVUA 2003 PM10 Attainment Plan (Bakersfield - Golden State monitoring station).
7. Per SJVUAPCD, regional background of ammonium sulfate is estimated to be 1 μg/m^3.
8. Contribution from sources within Kern County is 50% of net concentration after previous adjustment to Vegetative Burning category.
9. SOx inventory for Kern County that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
10. PM10 County Impact divided by Ammonium Sulfate County Impact.

Supplement C
Development of NOx/PM_{10} and SO_2/PM10 Inter-pollutant Offset Ratio for Fresno County

1.0 Introduction

The San Joaquin Valley Unified Air Pollution Control District is a PM_{10} non-attainment area with respect to both the federal and California ambient standards for this pollutant. The Panoche Energy Center proposed for Fresno County would result in PM_{10} emissions from various onsite stationary source units. Because the background concentrations already exceed the National and California ambient standards for this pollutant, such emissions increases in PM_{10} have the potential to exacerbate existing exceedances. Accordingly, SJVAPCD regulations require a project that will cause an increase in PM_{10} emissions to provide offsets in sufficient amounts to provide a net air quality benefit.

Reductions of SO_x and NO_x emissions can be used to offset the PM_{10} impact from a new source within the SJVAPCD, because sulfates and nitrates are precursors of particulate matter. In order to quantify the offset requirement when such interpollutant trading is used, the appropriate ratios between PM_{10} and SO_x and PM_{10} and NO_x must be calculated. According to SJVAPCD policy (Sweet, 2006), inter-pollutant trading ratios specific to the Panoche project area can be calculated using results of Chemical Mass Balance (CMB) modeling conducted by SJVAPCD staff as part of the District's 2003 PM_{10} Attainment Plan. As recently as the spring of 2006, URS was informed by SJVAPCD that the assumptions, monitoring data, emissions inventory data and calculation methods used in the Attainment Plan are sufficiently recent to be considered valid for the purpose of estimating current SO_x/PM_{10} and NO_x/PM_{10} interpollutant offset ratios.

2.0 CMB Modeling Results and Annual Roll Back Analysis

Receptor modeling using the chemical mass balance model was conducted by SJVAPCD for sites in the project area that currently do not comply with the federal PM_{10} air quality standards. This method uses chemical analysis of collected air monitoring samples and information about the chemical composition of contributing sources to evaluate the link between observed concentrations and contributing emission sources. The SJVAPCD used the results of its CMB analysis with a modified rollback approach to calculate the effects on design particulate values that would result from implementation of adopted and proposed control measures to reduce PM_{10} pollution and other predicted emission trends for the most recent PM_{10} Attainment Plan. The results can also be used to support calculation of interpollutant offset ratios, as described later. The data used for this purpose were taken from an Excel workbook titled N2-Annual Rollback Analysis which was provided by SJVAPCD. Tables 1-4 summarize the data from the N2 Rollback Analysis that are relevant to this application

Table 1 presents monthly and annual average CMB modeling results for Fresno County. This includes measured PM10 concentrations at the Fresno Drummond monitoring site and model predicted contributions to these concentrations due to various source types. Table 2 shows the annual average CMB modeling results and design values for the SJVAPCD areas that are noncompliant with the PM_{10} standards from Table 1, including Fresno Drummond results. The design values were determined using EPA calculation methods (EPA 2004) and the air quality monitoring data collected in Fresno County. In Table 2, 'Sum of Species' represents the summation of the mass concentrations across all source categories, including 'Burning', 'Motor Vehicle', 'Tire/Brake', 'Sulfate', 'Nitrate', and 'Geological'. The value difference between 'Sum of Species' and 'Design Value' was left in the "unassigned" column.

The rollback analyses conducted by SJVAPCD used a speciation model with the CMB results. This modified rollback analysis showed not only the speciation, but also how the species were distributed and estimated source attributions for both primary and secondary pollutant species. The rollback analysis also considered other factors, including geological information, PM, VOC, and NO_x inventory totals, and other relevant information. Separate modeling was conducted in the rollback analysis for each county to account for conditions and characteristics that are unique to specific areas of the SJVAPCD. The rollback analysis for Fresno County is shown in the tab labeled "Fresno" within the Excel Workbook provided in Attachment 1 "N2-Annual Rollback Analysis".

The SJVAPCD rollback analysis was conducted as follows. Line 1 in Table 3 shows the concentration values influenced by the local area emissions. The 'Annual design value' equivalent to the chemistry of the CMB monthly analysis of the Fresno Drummond data in the Table 2 matches with the 'General Note' in Line 1 of Table 3. The mass concentrations of 'Geological', 'Mobile', 'Tire/Brake', and 'Unassigned' in Table 2 are equivalent to the corresponding attributes in line 1 of Table 3. The cells in Line 1 for vegetative burning and organic carbon represent 70% and 30% respectively of the value for 'Burning' in Table 2.

Line 2 of Table 3 shows concentration values for the natural and transport contributions for each attribute, which come from background concentration measurements. Line 3 is the 'net for rollback' concentrations, which means the differences in values between Line 1 and Line 2. The values of Line 3 are distributed to Line 4 through Line 7 based on the area of influence and the percentage distribution of PM10 source categories used by SJVAPCD. The attributes of 'Geological and Construction', 'Tire/Brake', and 'Unassigned' follow the corresponding percentages of PM_{10} distribution. The attributes of 'Mobile', 'Organic Carbon', 'Vegetation Burning', 'Ammonium Nitrate', and 'Ammonium Sulfate' follow the percent of $PM_{2.5}$ distribution. Lines 4 and 5 represent the local contribution of $PM_{2.5}$ minus PM_{10} and $PM_{2.5}$, respectively. Line 6 presents the sub-regional contribution, and Line 7 shows the regional contributions.

The most current emission inventory (lb/day) for PM_{10}, NO_x, total organic compounds (TOG) and SO_x for the Fresno-Madera area is provided in Table 4.

Values from Tables 3 and 4 were used to calculate the inter-pollutant trading ratio for Fresno County. The methods employed for these calculations are addressed in the next section.

Table 1 Monthly and Annual Average CMB results at the Fresno Drummond site for February to December 2000 plus the January 2001 Episode (all concentrations are in $\mu g/m^3$)

Fresno Drummond Monthly

SITE ID	DATE	CONC	UCONC	PCMASS	RSQ	CHISQ	Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological	
							Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc
FSD	1/1/01	186	9.4	87.9	1.0	1.1	40.1	11.3	18.5	9.6	2.5	1.5	5.0	0.7	62.4	5.1	35.1	6.8
FSD	Feb	27.0	2.1	97.3	1.0	0.7	5.7	2.5	3.1	1.8	0.3	0.4	1.1	0.2	7.7	0.8	8.3	2.1
FSD	Mar	23.9	2.1	116.0	1.0	0.7	4.6	2.4	3.1	1.8	0.1	0.4	1.8	0.2	8.2	0.9	9.9	2.3
FSD	Apr	24.8	2.2	112.1	1.0	0.6	3.4	2.7	2.4	1.6	0.2	0.5	2.4	0.2	5.0	0.5	14.4	3.0
FSD	May**	20.0	2.1	99.5	1.0	0.6	0.345	0.329	2.1	1.4			2.327	0.226	2.4774	0.3211	12.6	1.7055
FSD	Jun*	34.1	2.5	105.8	1.0	1.0	1.9	0.4	3.8	2.3	0.0	0.6	4.2	0.4	3.6	0.4	22.5	3.8
FSD	Jul*	26.4	2.3	100.6	1.0	0.6	1.0	0.4	1.5	1.3			1.7	0.2	2.7	0.3	19.6	2.2
FSD	Aug*	38.2	2.5	90.2	0.9	2.7	3.8	0.7	0.9	1.5	1.4	0.9	2.0	0.3	3.3	0.4	23.1	4.3
FSD	Sep*	56.7	3.3	92.8	1.0	0.9	1.5	0.6	3.4	2.5	0.9	1.0	2.6	0.4	3.6	0.4	40.6	6.0
FSD	Oct*	50.7	3.4	93.5	1.0	0.5	1.8	0.4	4.5	2.6			2.2	0.3	8.4	0.8	30.6	3.3
FSD	Nov	40.5	2.6	95.7	1.0	0.4	11.9	3.3	4.5	2.7	0.4	0.4	2.1	0.2	13.1	1.2	6.8	1.8
FSD	Dec	65.8	3.9	89.7	1.0	0.8	13.7	4.3	7.3	3.8	0.8	0.6	3.2	0.3	23.4	2.0	10.6	2.6
Min		20.0	2.1	87.9	0.9	0.4	0.3	0.3	0.9	1.3	0.0	0.4	1.1	0.2	2.5	0.3	6.8	1.7
Avg		49.5	3.2	98.4	1.0	0.9	7.5	2.4	4.6	2.8	0.7	0.7	2.6	0.3	12.0	1.1	19.5	3.3
Max		186.0	9.4	116.0	1.0	2.7	40.1	11.3	18.5	9.6	2.5	1.5	5.0	0.7	62.4	5.1	40.6	6.8

Note:
CONC: concentration
UCONC: Uncertainty of concentration
PCMASS: Percent of mass
RSQ: R square
CHISQ: Chi square
Mass: concentration based on mass
UNC: Uncertainty of concentration based on mass

Table 2 **Annual Average CMB results and Design Value for the Counties Noncompliant with the Standards (50) in San Joaquin Valley Unified Air Pollution Control District (All concentrations in $\mu g/m^3$)**

SITE ID	CONC	UCONC	PCMASS	Design Value *	Sum of species	Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological		Geological	Un-assigned
						Mass	UNC	Mass	UNC	Mass	UNC	Mass	UNC	Mass	UNC	Mass	UNC	Profile	
BGS	57.7	3.6	98.5	57.0	55.6	6.3	2.3	3.6	2.4	1.1	1.2	3.0	0.3	14.9	1.3	26.7	5.8	FDKERANN	1.4
FSD	**49.5**	**3.2**	**98.4**	**50.0**	**46.9**	**7.5**	**2.4**	**4.6**	**2.8**	**0.7**	**0.7**	**2.6**	**0.3**	**12.0**	**1.1**	**19.5**	**3.3**	**FDFSDANN**	**3.1**
HAN	51.5	3.3	104.1	53.0	52.9	6.6	2.0	4.0	2.3	0.5	0.7	3.0	0.3	15.7	1.4	23.2	4.2	FDHANANN	0.1
VCS	52.5	3.3	99.6	54.0	51.8	6.7	2.5	4.0	2.5	0.5	1.0	3.1	0.3	15.9	1.5	21.7	3.8	FDVCSANN	2.2

Note:

* All Design Values are equal to or exceed the California 24-Hour Standard (50 $\mu g/m^3$)

BGS: Bakersfield Golden State for Kern County

FSD: Fresno Drummond for Fresno County

HAN: Hanford for Kings County

VCS: Visalia Church Street for Tulare County

Unassigned: Mass based concentration that CMB model did not assign to attribute.

Table 3
SJVAPCD N2 Annual Rollback Analysis (Concentrations on Lines 1 through 7 are in $\mu g/m^3$)

Fresno - Drummond, Annual, Design value = 50 μg/m3	General Note	Geologic and Construction	Mobile Exhaust	Tire and Brake Wear	Organic Carbon	Vegetative Burning	Ammonium Nitrate including associated water	Ammonium Sulfate	Marine	Unassigned
Line1 Source Contribution from Analysis	From CMB monthly analysis Feb 2000 to Dec 2000, adding January 2001 episode for chemistry equivalent to annual design value	From CMB	From CMB	From CMB	Estimated portion of mass included in Vegetative Burning =30%	From CMB minus estimated Organic Carbon from other sources	From CMB	From CMB	From CMB, if present	Unaccounted mass from CMB, if any.
LINE 1	**50.00**	**19.50**	**4.60**	**0.70**	**2.25**	**5.25**	**12.00**	**2.60**	**0.00**	**3.1**
Line2 Natural and Transport Contribution, see "Background" sheet	Portion not included in rollback analysis, removed prior to rollback as not subject to local control, added back to projected future concentrations	See background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	0, no natural background, transport estimated at 0	0, no natural background, transport estimated at 0	See background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes biogenic emissions. = 20%	See background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes wildfires and biogenic. =20% + 10%	See background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	See background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	100% because marine salts are a natural emission	0, background estimate at maximum, no additional background estimate for unexplained mass
LINE 2	**8.25**	**4.0**	**0.0**	**0.0**	**0.7**	**1.6**	**1.0**	**1.0**		
Line 3 Net for Rollback	Net for Rollback, default percentages adjustable for episode characteristics, applicable to all columns except						Net for non-linear rollback, default percentages adjustable for episode characteristics		Removed entirely from rollback, added back to result	

Fresno - Drummond, Annual, Design value = 50 µg/m3	General Note	Geologic and Construction	Mobile Exhaust	Tire and Brake Wear	Organic Carbon	Vegetative Burning	Ammonium Nitrate including associated water	Ammonium Sulfate	Marine	Unassigned
	as indicated.									
LINE 3 Line4 Local Contribution PM2.5-PM10 Area of Influence	**41.75** Source contribution from smallest area of influence, representative of large particle primary source area, includes all PM size emissions in the area - Rolled back against local area of influence emission estimates	**15.5** 70%PM10 50%PM2.5 of net	**4.6** 70%PM10 50%PM2.5 of net	0.7 70%PM10 50%PM2.5 of net	**1.6** 70%PM10 50%PM2.5 of net	3.7 70%PM10 50%PM2.5 of net	11.0 70%PM10 50%PM2.5 of net, non-linear rollback	**1.6** 70%PM10 50%PM2.5 of net	0.0	3.1 70%PM10 50%PM2.5 of net
LINE 4 Line5 Local Contribution Area of Influence of PM2.5	**24.74** Rolled back against local PM2.5 area of influence emission estimates - episode specific adjustments based on meteorology and episode duration	**10.9** 15%PM10 30%PM2.5	2.3 15%PM10 30%PM2.5	0.5 15%PM10 30%PM2.5	**0.8** 15%PM10 30%PM2.5	**1.8** 15%PM10 30%PM2.5	5.5 15%PM10 30%PM2.5 non-linear rollback	0.8 15%PM10 30%PM2.5		**2.2** 15%PM10 30%PM2.5
LINE 5 Line6 Sub regional Contribution	9.63 Rolled back against specified County(ies) emission estimates - episode specific	2.3 10%PM10 15%PM2.5	1.4 10%PM10 15%PM2.5	0.1 10%PM10 15%PM2.5	**0.47** 10%PM10 15%PM2.5	1.1 10%PM10 15%PM2.5	3.3 10%PM10 15%PM2.5 non-linear rollback	0.5 10%PM10 15%PM2.5		**0.5** 10%PM10 15%PM2.5

Fresno - Drummond, Annual, Design value = 50 μg/m3	General Note	Geologic and Construction	Mobile Exhaust	Tire and Brake Wear	Organic Carbon	Vegetative Burning	Ammonium Nitrate including associated water	Ammonium Sulfate	Marine	Unassigned
	adjustments based on meteorology and episode duration									
LINE 6 ine7 Regional contribution	**5.30** Rolled back against Valley-wide emission estimates - episode specific adjustments based on meteorology and episode duration	**1.6** 5%PM10 5%PM2.5	**0.7** 5%PM10 5%PM2.5	**0.1** 5%PM10 5%PM2.5	**0.24** 5%PM10 5%PM2.5	**0.6** 5%PM10 5%PM2.5	**1.65** 5%PM10 5%PM2.5 non-linear rollback	**0.24** 5%PM10 5%PM2.5	[redacted]	**0.3** 5%PM10 5%PM2.5
LINE 7 ssociated missions ategories	**2.09** Based upon appropriate seasonal or annual inventory	**0.8** PM10 paved roads+ PM10 unpaved roads+ PM10 off road mobile+ PM10 farm operations+ PM10 construction+ PM10 windblown	**0.2** PM10, TOG & CO onroad mobile+ PM10, TOG & CO 860 offroad equipment PM10, TOG & CO 870 farm equipment CO presumed to add minimal mass	**0.0** Tire and brake wear as predicted by EMFAC2002	**0.08** Total TOG minus motor vehicle, OC may also include a small portion of otherwise unassigned elemental carbon PM10 & CO Area, Stationary CO presumed to add minimal mass	**0.2** PM10 & CO residential burning PM10 & CO waste burning and disposal PM10 cooking PM10 & CO fires CO presumed to add minimal mass	**0.55** Total E.I. NOx (+ bacterial soil NOx estimate removed as natural background)	**0.08** Total SOx	[redacted] None, natural emission from the ocean, bay and delta waters	**0.2** Total PM10

Table 4 Emission Inventory for Year 1999 through Current Year (valid for this project)- All emissions in tons per day

Emissions Inventory	Area of Influence	Geologic and Construction	Mobile Exhaust	Tire and Brake Wear	Organic Carbon	Vegetative Burning	Ammonium Nitrate including associated water	Ammonium Sulfate	Marine	Unassigned
PM10	Fresno	74.4504	4.1236	0.511	5.6266	10.4843				39.92145356
NOx	Fresno						174.7763			
TOG	Fresno		58.2653		396.7168					
SOx	Fresno							9.0772		

3.0 Interpollutant Trading Ratio

The SJVAPCD (Sweet, 2005) provided the interpollutant trading calculation method, which is presented in Tables 5, 6, and 7. Summing 'organic carbon' and 'vegetation burning' from Line 1 in Table 3 gave the value of 'Vegetative Burning Total' in Table 5. 'Industry Component' and 'Regional Background' were calculated as 30% and 20% of the'Vegetative Burning Total', respectively. The value for 'Regional Background' was subtracted from the 'Industry Component' to obtain the 'Industry minus Background' value. The value for 'County Contribution' was estimated to be 50% of the value of 'Industry minus Background'. The value for 'Organic Carbon PM_{10} Inventory-Fresno County' was obtained from the emission inventory shown in Table 4. The value for 'County Contribution' divided by the value of 'Organic Carbon PM_{10} Inventory' gave the 'County Impact' in units of $\mu g/m^3$ per ton.

The values of 'Ammonium Sulfate' and 'Regional Background' in Table 6 were obtained from the values of 'Ammonium Sulfate' in Lines 1 and 2 in Table 4, respectively. The value of 'Ammonium Sulfate' was reduced by the value of 'Regional Background' to obtain the entry labeled 'Ammonium Sulfate minus Background'. The value for 'County Contribution' was also determined as 50% of the value of 'Ammonia Sulfate minus Background'. The value of 'SO_x Inventory-Fresno County' was obtained from the emission inventory shown in Table 4. The value of 'County Contribution' divided by the value of 'SO_x Inventory' gave the 'County Impact' in units of $\mu g/m^3$ per ton.

The inter-pollutant trading ratio of SO_2 to PM_{10} was calculated as the ratio of the 'County Impact' of PM_{10} to the 'County Impact' of SO_x. The ratio is 1.8 (tons of SO_2 to equal the effect of 1 ton of PM_{10} reduction). Likewise, the interpollutant trading ratio of NO_2 to PM_{10} was calculated in Table 7 as a ratio of the 'County Impact' of PM_{10} to the 'County Impact' of NO_x. The resulting ratio is 3.0 (tons of NO_2 to equal the effect of reducing 1 ton of PM_{10}).

Table 5 PM_{10} County Impact

PM_{10}	Note	Units	Estimate	Uncertainty
"Vegetative Burning" Total	1	$\mu g/m^3$	7.50	2.43
Industry Component (30%)	2	$\mu g/m^3$	2.25	
Regional Background (20%)	3	$\mu g/m^3$	0.45	
Industry minus Background		$\mu g/m^3$	1.80	
County Contribution	4	$\mu g/m^3$	0.90	
Organic Carbon PM_{10} Inventory - Fresno County	5	ton/day	5.63	
County Impact		$\mu g/m^3$ per ton	0.16	0.21

Table 6 SO_x County Impact and Inter-pollutant trading ratio of SO_x and PM_{10}

Sulfate	Note	Units	Estimate	Uncertainty
Ammonia Sulfate	6	$\mu g/m^3$	2.60	0.29
Regional Background	7	$\mu g/m^3$	1.00	
Ammonium Sulfate minus Background		$\mu g/m^3$	1.60	
County Contribution	8	$\mu g/m^3$	0.80	
SO_x Inventory - Fresno County	9	ton/day	9.08	
County Impact		$\mu g/m^3$ per ton	0.09	0.10
Tons of SO_x to Equal Effect of 1 ton PM_{10} Reduction	10		**1.8**	2.2

Table 7 NOx County Impact and Inter-pollutant trading ratio of NO_x and PM_{10}

Nitrate	Note	Units	Estimate	Uncertainty
Ammonium Nitrate	11	$\mu g/m^3$	12.00	0.29
Regional Background	12	$\mu g/m^3$	1.00	
Ammonium Nitrate minus Background		$\mu g/m^3$	11.00	
County Contribution	13	$\mu g/m^3$	5.50	
NOx Inventory - Fresno	14	ton/day	174.7763	
County Impact		$\mu g/m^3$ per ton	0.03	0.03
Tons of NO_x to Equal Effect of 1 ton PM_{10} Reduction	15		**3.0**	4.0

Note:

1. Per SJVUAPCD and CARB, PM_{10} emissions from stationary industrial combustion sources are included in the Vegetative Burning category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM_{10} Attainment Plan (Fresno-Drummond monitoring station).
2. Per SJVUAPCD, 30% of this category is attributed to stationary industrial combustion sources.
3. Per SJVUAPCD, regional background is estimated to be 20% of net concentration after previous adjustment to Vegetative Burning category.
4. Contribution from sources within Fresno County is estimated to be 50% of net concentration after previous adjustments to Vegetative Burning category.
5. Organic carbon PM_{10} inventory for Fresno County that contributes to this monitoring location; from SIP inventory with updates and adjustments based on Central California Ozone Study (CCOS) study.

6. Ammonium sulfate category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM_{10} Attainment Plan (Fresno-Drummond monitoring station).
7. Per SJVUAPCD, regional background of ammonium sulfate is estimated to be 1 mg/m^3.
8. Contribution from sources within Fresno is estimated to be 50% of net concentration after previous adjustment to Vegetative Burning eategory.
9. SO_x inventory for Fresno that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
10. PM_{10} County Impact divided by Ammonium Sulfate County Impact.
11. Ammonium nitrate category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM_{10} Attainment Plan (Fresno - Drummond monitoring station).
12. Per SJVUAPCD, regional background of ammonium nitrate is estimated to be 1 mg/m^3.
13. Contribution from sources within Fresno County is estimated to be 50% of net concentration after previous adjustment to Vegetative Burning category.
14. NO_x inventory for Fresno County that contributes to this monitoring location; from SIP inventory with updates and adjustments based on Central California Ozone Study (CCOS) study.
15. PM_{10} County Impact divided by Ammonium Nitrate County Impact.

4.0 Reference

1) EPA-CMB8.2 Users Manual, December, 2004
2) San Joaquin Valley Air Pollution Control District State Implementation Plan PM10 Modeling Protocol (SJVAPCD, 2005)
3) Attachment 6 and calculation method obtained from SJVAPCD (James Sweet, james.sweet@valleyair.org, 559-230-5810)

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Fresno - Drummond, Annual, Design value = 50	General Note	Geologic and Construction	Mobile Exhaust		Tire and Brake Wear	Organic Carbon		Vegetative Burning	Ammonium Nitrate Including associated water	Ammonium Sulfate	Marine	Unassigned
2	Line1 Source Contribution from Analysis	From CMB monthly analysis Feb 2000 to Dec 2000, adding January 2001 episode for chemistry equivalent to annual design value	From CMB	From CMB		From CMB	Estimated portion of mass included in Vegetative Burning +30%		From CMB minus estimated Organic Carbon from other sources	From CMB	From CMB	From CMB, if present	Unaccounted mass from CMB, if any.
3	LINE 1	50.00	19.50	4.60		0.70	2.25		5.25	12.00	2.60	0.00	3.1
4	Line2 Natural and Transport Contribution, see "Background" sheet	Portion not included in rollback analysis, removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	0, no natural background transport estimated at 0		0, no natural background, transport estimated at 0	see background sheet for numerical estimate and episode adjustment Removed prior to rollback as not subject to local control, added back to projected future concentrations Includes biogenic emissions		see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations Includes wildfires and biogenic	see background sheet for numerical estimate and episode adjustment Removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	100% because marine salts are a natural emission	0, background estimate at maximum, no additional background estimate for unexplained mass
5	LINE 2	8.25	4.0	0.0		0.0	0.7		1.6	1.0	1.0		
6	Line 3 Net for Rollback	Net for Rollback, default percentages adjustable for episode characteristics, applicable to all columns except as indicated								Net for non-linear rollback, default percentages adjustable for episode characteristics		Removed entirely from rollback, added back to result	
7	LINE 3	41.75	15.5	4.8		0.7	1.6		3.7	11.0	1.6	0.0	3.1
8	Line4 Local Contribution PM2.5-PM10 Area of Influence	Source contribution from smallest area of influence, representative of large particle primary source area, includes all PM size emissions in the area - Rolled back against local area of influence emission estimates	70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net, non-linear rollback	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net
9	LINE 4	24.74	10.9	2.3		0.5	0.8		1.8	5.5	0.8		2.2
10	Line5 Local Contribution Area of Influence of PM2.5	Rolled back against local PM2.5 area of influence emission estimates - episode specific adjustments based on meteorology and episode duration	15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5 non-linear rollback	15%PM10 30%PM2.5		15%PM10 30%PM2.5
11	LINE 5	9.63	2.3	1.4		0.1	0.47		1.1	3.3	0.5		0.5
12	Line6 Sub regional Contribution	Rolled back against specified County(ies) emission estimates - episode specific adjustments based on meteorology and episode duration	10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5 non-linear rollback	10%PM10 15%PM2.5		10%PM10 15%PM2.5
13	LINE 6	5.30	1.6	0.7		0.1	0.24		0.6	1.65	0.24		0.3
14	Line7 Regional Contribution	Rolled back against Valleywide emission estimates - episode specific adjustments based on meteorology and episode duration	5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5 non-linear rollback	5%PM10 5%PM2.5		5%PM10 5%PM2.5
15	LINE 7	2.09	0.8	0.2		0.0	0.08		0.2	0.55	0.08		0.2
16	Associated Emissions Categories	Based upon appropriate seasonal or annual inventory	PM10 paved roads+ PM10 unpaved roads+ PM10 off road mobile+ PM10 farm operations+ PM10 construction+ PM10 windblown	PM10, TOG & CO onroad mobile+ PM10, TOG & CO 860 offroad equipment PM10, TOG & CO 870 farm equipment CO presumed to add minimal mass		Tire and brake wear as predicted by EMFAC2002	Total TOG minus motor vehicle. OC may also include a small portion of otherwise unassigned elemental carbon PM10 & CO Area, Stationary CO presumed to add minimal mass		PM10 & CO residential burning PM10 & CO waste burning and disposal PM10 cooking PM10 & CO fires CO presumed to add minimal mass	Total E.I. NOx (+ bacterial soil NOx estimate removed as natural background)	Total SOx	None, natural emission from the ocean, bay and delta waters	Total PM10
17	1999 Emissions Inventory	(area of influence emissions inventory, each on a separate line for automated calculations)											
18	PM10	L1= Area 3	7.236852297	1.55746265		0.270246847	1.54732371		2.946320228				15.67665618
19		L2= Areas 3,4	26.02510179	2.26760773		0.375484561	2.955506973		5.732736172				39.92145356
20		Sr= Fresno, Madera	74.4504	4.1236		0.511	5.6286		10.4643				94.6839
21		R= SJV	230.9463	14.9086		1.92	24.7496		34.9152				305.5217
22	NOx	L1= Area 3								53.21469079			
23		L2= Areas 3,4								88.61773631			
24		Sr= Fresno, Madera								144.7763			
25		R= SJV								565.19			
26	TOG	L1= Area 3			22.7065618			132.7691237					
27		L2= Areas 3,4			33.470797			257.8874576					
28		Sr= Fresno, Madera			56.2653			396.7168					
29		R= SJV			205.9787			1241.6439					
30	SOx	L1= Area 3									3.438823609		
31		L2= Areas 3,4									5.665348961		
32		Sr= Fresno, Madera									9.0772		
33		R= SJV									30.2452		

	A	B	C	D	E	F	G	H	I	J	K	L	M
		General Note	Geologic and Construction	Mobile Exhaust		Tire and Brake Wear	Organic Carbon		Vegetative Burning	Ammonium Nitrate including associated water	Ammonium Sulfate	Marine	Unassigned
1	Fresno - Drummond, Annual, Design value = 50												
133	2010-2011 Emissions Inventory [illegible]												
134	PM10 2010 EI without new controls	L1= Area 3	8.129557867	1.44348865		0.367960339	1.747683078		3.262499732				17.31537711
135		L2= Areas 3,4	29.27326118	2.15521975		0.543853899	3.283480261		6.107826372				44.15866903
136		Sr= Fresno, Madera	83.727	3.8288		0.746828157	6.2618		10.6882				104.7058
137		R= SJV	255.0794	13.3523		2.63	27.9931		35.1798				331.6046
138	PM10 2010 EI with new controls	L1= Area 3	6.809440309	1.38943472		0.367960339	1.5244012		2.850942087				15.31078142
139		L2= Areas 3,4	24.51972578	2.07451381		0.543853899	2.863986791		4.982912068				37.05429837
140		Sr= Fresno, Madera	70.131	3.68542395		0.746828157	5.4618		8.8472				84.47342395
141		R= SJV	205.8304	12.8523		2.63	26.3051		29.2898				285.2426
142	NOx 2010 EI without new controls	L1= Area 3								34.57241458			
143		L2= Areas 3,4								62.07171354			
144		Sr= Fresno, Madera								103.4162			
145		R= SJV								401.6388			
146	NOx 2010 EI with new controls	L1= Area 3								31.73589191			
147		L2= Areas 3,4								56.97898788			
148		Sr= Fresno, Madera								94.93133136			
149		R= SJV								364.0558			
150	TOG 2010 EI without new controls	L1= Area 3			11.5234286			156.7815607					
151		L2= Areas 3,4			17.8329166			304.4959518					
152		Sr= Fresno, Madera			31.9684			468.3626					
153		R= SJV			111.1259			1484.1355					
154	TOG 2010 EI with new controls	L1= Area 3			11.5234286			156.7815607					
155		L2= Areas 3,4			17.8329166			304.4959518					
156		Sr= Fresno, Madera			31.9684			468.3626					
157		R= SJV			111.1259			1458.6195					
158	SOx 2010 EI without new controls	L1= Area 3									4.027627725		
159		L2= Areas 3,4									6.605602158		
160		Sr= Fresno, Madera									10.8469		
161		R= SJV									33.341		
162	SOx 2010 EI with new controls	L1= Area 3									3.749205461		
163		L2= Areas 3,4									6.148969412		
164		Sr= Fresno, Madera									9.9109		
165		R= SJV									27.083		
210													
211	2010-2011 Rollback Projection [illegible]												
212	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	12.2	1.1	0.6	0.7	0.4	0.5	2.0	4.2	0.9		2.4
213	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	2.6	0.7	0.4	0.2	0.3	0.3	1.2	2.6	0.6		0.5
214	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	1.7	0.3	0.2	0.1	0.1	0.1	0.6	1.3	0.3		0.3
215	Regional Contribution	=(2010 R/1999 R) * LINE 7	0.9	0.1	0.1	0.0	0.0	0.0	0.2	0.4	0.1		0.2
216	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.7		1.6	1.0	1.0	0.0	0.0
217	2010-2011 projected Annual Result	49.67	21.4	2.1	1.2	1.0	1.6	0.9	5.5	9.6	2.9	0.0	3.4
218	[illegible]												
219	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	10.2	1.0	0.6	0.7	0.4	0.5	1.7	4.0	0.9		2.1
220	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	2.2	0.6	0.4	0.2	0.2	0.3	1.0	2.5	0.5		0.4
221	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	1.5	0.3	0.2	0.1	0.1	0.1	0.5	1.3	0.3		0.3
222	Regional Contribution	=(2010 R/1999 R) * LINE 7	0.7	0.1	0.1	0.0	0.0	0.0	0.2	0.4	0.1		0.1
223	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.7		1.6	1.0	1.0	0.0	0.0
224	2010-2011 projected Annual Result	44.88	18.8	2.1	1.2	1.0	1.4	0.9	4.8	9.2	2.7	0.0	3.0
225													

Attachment 2

District Review and Approval

PM10 Interpollutant Offset Ratio Analysis
for Fresno County

PM10

	Notes	Units	Estimate	Uncertainty		
"Vegetative Burning" Total	1	$\mu g/m^3$	7.48	2.43		"Annual based on Monthly" speciation worksheet cells G6 and H6
Industry Component (30%)	2	$\mu g/m^3$	2.24			"Fresno Annual" worksheet for speciated rollback analysis
Regional Background (20%)	3	$\mu g/m^3$	0.45			"
Industry minus Background		$\mu g/m^3$	1.80			"
County Contribution	4	$\mu g/m^3$	0.90			"
Organic Carbon PM10 Inventory - Fresno/Madera Co.	5	ton/day	5.63			" Required to use base year emissions that are related to the observed speciation
County Impact		$\mu g/m^3$ per ton	0.16	0.21		
				0.11		

Sulfate

	Notes	Units	Estimate	Uncertainty		
Ammonium Sulfate	6	$\mu g/m^3$	2.55	0.30		Annual based on Monthly, speciation worksheet cells M6 and N6
Regional Background	7	$\mu g/m^3$	1.00			"Fresno Annual" worksheet for speciated rollback analysis
Ammonium Sulfate minus Background		$\mu g/m^3$	1.55			"
County Contribution	8	$\mu g/m^3$	0.78			"
SOx Inventory - Fresno/Madera Counties	9	ton/day	9.08			" Required to use base year emissions that are related to the observed speciation
County Impact		$\mu g/m^3$ per ton	0.09	0.10		
				0.08		
Tons of SOx to Equal Effect of 1 Ton of PM10	10		1.866	2.21	0.35	
				1.43	-0.44	

1. Per SJVUAPCD and CARB, PM10 emissions from stationary industrial combustion sources are included in the Vegetative Burning category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM10 Attainment Plan (Fresno - Drummond monitoring station).
2. Per SJVUAPCD, 30% of this category is attributed to stationary industrial combustion sources.
3. Per SJVUAPCD, regional background is estimated to be 20% of net concentration after previous adjustment to Vegetative Burning category.
4. Contribution from sources within Fresno & Madera Counties is 50% of net concentration after previous adjustments to Vegetative Burning category.
5. Organic carbon PM10 inventory for Fresno/Madera Counties that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
6. Ammonium sulfate category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM10 Attainment Plan (Fresno - Drummond monitoring station).
7. Per SJVUAPCD, regional background of ammonium sulfate is estimated to be 1 $\mu g/m^3$.
8. Contribution from sources within Fresno County is 50% of net concentration after previous adjustment to Vegetative Burning category.
9. SOx inventory for Fresno/Madera Counties that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
10. PM10 County Impact divided by Ammonium Sulfate County Impact.

Notes for the Fresno/Madera Interpollutant Analysis

Combined emissions and inventories from Fresno and Madera Counties are used due to the evaluations of source interactions.
This relationship was established by analysis performed for the SJVAPCD PM10 SIP.

The interpollutant relationship established for Fresno County in this analysis would also be applicable to Madera County.

Tons of SOx to Equal Effect of 1 Ton of PM10	1.866	See SOxPM10 worksheet for calculations
Tons of NOx to Equal Effect of 1 ton PM10	4.202	See NOxPM10 worksheet for calculations

Input data for the interpollutant worksheets are from the Annual and Annual based on Monthly worksheets
These worksheets are data and analyses submitted for the PM10 SIP
The AOI worksheet provides area of influence evaluations used to analyze specific episodes in the PM10 SIP
Episode evaluations reveal a variety of source areas for different episodes.
This justifies the use of the entire county, and in some cases more than one county, as the source area for annual interpollutant evalaution.

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Fresno - Drummond, Annual, Design value = 50**	General Note	Geologic and Construction	Mobile Exhaust		Tire and Brake Wear	Organic Carbon		Vegetative Burning	Ammonium Nitrate Including associated water	Ammonium Sulfate	Marine	Unassigned
2	Line1 Source Contribution from Analysis	From CMB monthly analysis Feb 2000 to Dec 2000, adding January 2001 episode for chemistry equivalent to annual design value	From CMB	From CMB		From CMB	Estimated portion of mass included in Vegetative Burning =30%		From CMB minus estimated Organic Carbon from other sources	From CMB	From CMB	From CMB, if present	Unaccounted mass from CMB, if any.
3	LINE 1	50.00	19.50	4.60		0.70	2.25		5.25	12.00	2.80	0.00	3.1
4	Line2 Natural and Transport Contribution, see "Background" sheet	Portion not included in rollback analysis, removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	0, no natural background, transport estimated at 0		0, no natural background, transport estimated at 0	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations Includes biogenic emissions		see background sheet for numerical estimate and episode adjustment Removed prior to rollback as not subject to local control, added back to projected future concentrations Includes wildfires and biogenic	see background sheet for numerical estimate and episode adjustment Removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	100% because marine salts are a natural emission	0, background estimate at maximum, no additional background estimate for unexplained mass
5	LINE 2	8.03	4.0	0.0		0.0	0.5		1.6	1.0	1.0		
6	Line 3 Net for Rollback	Net for Rollback, default percentages adjustable for episode characteristics, applicable to all columns except as indicated								Net for non-linear rollback, default percentages adjustable for episode characteristics		Removed entirely from rollback, added back to result	
7	LINE 3	41.98	15.5	4.6		0.7	1.8		3.7	11.0	1.6	0.0	3.1
8	Line4 Local Contribution PM2.5-PM10 Area of Influence	Source contribution from smallest area of influence, representative of large particle primary source area. Includes all PM size emissions in the area - Rolled back against local area of influence emission estimates	70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net		70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net, non-linear rollback	70%PM10 50%PM2.5 of net	[illegible]	70%PM10 50%PM2.5 of net
9	LINE 4	24.85	10.9	2.3		0.5	0.9		1.8	5.5	0.8	[illegible]	2.2
10	Line5 Local Contribution Area of Influence of PM2.5	Rolled back against local PM2.5 area of influence emission estimates - episode specific adjustments based on meteorology and episode duration	15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5		15%PM10 30%PM2.5	15%PM10 30%PM2.5 non-linear rollback	15%PM10 30%PM2.5	[illegible]	15%PM10 30%PM2.5
11	LINE 5	9.70	2.3	1.4		0.1	0.54		1.1	3.3	0.5	[illegible]	0.5
12	Line6 Sub regional Contribution	Rolled back against specified County(ies) emission estimates - episode specific adjustments based on meteorology and episode duration	10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5		10%PM10 15%PM2.5	10%PM10 15%PM2.5 non-linear rollback	10%PM10 15%PM2.5	[illegible]	10%PM10 15%PM2.5
13	LINE 6	5.33	1.6	0.7		0.1	0.27		0.6	1.65	0.24	[illegible]	0.3
14	Line7 Regional Contribution	Rolled back against Valleywide emission estimates - episode specific adjustments based on meteorology and episode duration	5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5		5%PM10 5%PM2.5	5%PM10 5%PM2.5 non-linear rollback	5%PM10 5%PM2.5	[illegible]	5%PM10 5%PM2.5
15	LINE 7	2.10	0.8	0.2		0.0	0.09		0.2	0.55	0.08		0.2
16	Associated Emissions Categories	Based upon appropriate seasonal or annual inventory	PM10 paved roads+ PM10 unpaved roads+ PM10 off road mobile+ PM10 farm operations+ PM10 construction+ PM10 windblown	PM10, TOG & CO onroad mobile+ PM10, TOG & CO 860 offroad equipment PM10, TOG & CO 870 farm equipment CO presumed to add minimal mass		Tire and brake wear as predicted by EMFAC2002	Total TOG minus motor vehicle. OC may also include a small portion of otherwise unassigned elemental carbon PM10 & CO Area, Stationary CO presumed to add minimal mass		PM10 & CO residential burning PM10 & CO waste burning and disposal PM10 cooking PM10 & CO fires CO presumed to add minimal mass	Total E.I. NOx (+ bacterial soil NOx estimate removed as natural background)	Total SOx	None, natural emission from the ocean, bay and delta waters	Total PM10
17	1999 Emissions Inventory	(area of influence emissions inventory each on a separate line for automated calculations)											
18	PM10	L1= Area 3	7.236852297	1.55746285		0.270246847	1.54732371		2.946320226				15.87865618
19		L2= Areas 3,4	26.02510179	2.26760773		0.375484581	2.955506973		5.732736172				39.92145356
20		Sr= Fresno, Madera	74.4504	4.1236		0.511	5.6266		10.4843				94.6839
21		R= SJV	230.9463	14.9086		1.92	24.7496		34.9152				305.5217
22	NOx	L1= Area 3								53.21489079			
23		L2= Areas 3,4								88.81773631			
24		Sr= Fresno, Madera								144.7763			
25		R= SJV								565.19			
26	TOG	L1= Area 3			22.7065618			132.7691237					
27		L2= Areas 3,4			33.470797			257.8874576					
28		Sr= Fresno, Madera			58.2653			396.7168					
29		R= SJV			205.9787			1241.6439					
30	SOx	L1= Area 3									3.438823609		
31		L2= Areas 3,4									5.665348961		
32		Sr= Fresno, Madera									9.0772		
33		R= SJV									30.2452		

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Fresno - Drummond, Annual, Design value = 50	General Note	Geologic and Construction	Mobile Exhaust		Tire and Brake Wear	Organic Carbon		Vegetative Burning	Ammonium Nitrate Including associated water	Ammonium Sulfate	Marine	Unassigned
133	[illegible]												
134	PM10 2010 EI without new controls	L1= Area 3	8.129557667	1.44346865		0.367960339	1.747683078		3.262499732				17.31537711
135		L2= Areas 3,4	29.27328116	2.15521975		0.543853899	3.283480261		6.107828372				44.15868903
136		Sr= Fresno, Madera	63.727	3.8268		0.746828157	6.2818		10.8882				104.7058
137		R= SJV	255.0794	13.3523		2.63	27.9931		35.1798				331.8046
138	PM10 2010 EI with new controls	L1= Area 3	6.809440309	1.38943472		0.367960339	1.5244012		2.650942087				15.31078142
139		L2= Areas 3,4	24.51972578	2.07451381		0.543853899	2.863966791		4.862912068				37.05429637
140		Sr= Fresno, Madera	70.131	3.68542395		0.746828157	5.4818		8.8472				84.47342395
141		R= SJV	205.8304	12.8523		2.63	26.3051		29.2898				285.2426
142	NOx 2010 EI without new controls	L1= Area 3								34.57241458			
143		L2= Areas 3,4								62.07171354			
144		Sr= Fresno, Madera								103.4182			
145		R= SJV								401.8368			
146	NOx 2010 EI with new controls	L1= Area 3								31.73589191			
147		L2= Areas 3,4								56.97898788			
148		Sr= Fresno, Madera								94.93133138			
149		R= SJV								364.0558			
150	TOG 2010 EI without new controls	L1= Area 3			11.5234286			156.7815607					
151		L2= Areas 3,4			17.8329166			304.4959518					
152		Sr= Fresno, Madera			31.9684			468.3626					
153		R= SJV			111.1259			1484.1355					
154	TOG 2010 EI with new controls	L1= Area 3			11.5234286			156.7815607					
155		L2= Areas 3,4			17.8329166			304.4959518					
156		Sr= Fresno, Madera			31.9684			468.3626					
157		R= SJV			111.1259			1458.6195					
158	SOx 2010 EI without new controls	L1= Area 3									4.027627725		
159		L2= Areas 3,4									6.605602158		
160		Sr= Fresno, Madera									10.6489		
161		R= SJV									33.341		
162	SOx 2010 EI with new controls	L1= Area 3									3.749205461		
163		L2= Areas 3,4									6.148969412		
164		Sr= Fresno, Madera									9.9109		
165		R= SJV									27.083		
210													
211	2010/2011 Rollback Projection												
212	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	12.2	1.1	0.6	0.7	0.5	0.5	2.0	4.2	0.9		2.4
213	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	2.6	0.7	0.4	0.2	0.3	0.3	1.2	2.6	0.6		0.5
214	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	1.7	0.3	0.2	0.1	0.2	0.2	0.6	1.3	0.3		0.3
215	Regional Contribution	=(2010 R/1999 R) * LINE 7	0.8	0.1	0.1	0.0	0.1	0.1	0.2	0.4	0.1		0.2
216	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.5		1.6	1.0	1.0	0.0	0.0
217	2010-2011 projected Annual Result	49.71	21.4	2.1	1.2	1.0	1.5	1.1	5.5	9.6	2.9	0.0	3.4
218	[illegible]												
219	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	10.2	1.0	0.8	0.7	0.4	0.5	1.7	4.0	0.9		2.1
220	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	2.2	0.6	0.4	0.2	0.3	0.3	1.0	2.5	0.5		0.4
221	Sub regional Contribution	=(2010 Sr1/1999 Sr2) * LINE 6	1.5	0.3	0.2	0.1	0.1	0.2	0.5	1.3	0.3		0.3
222	Regional Contribution	=(2010 R/1999 R) * LINE 7	0.7	0.1	0.1	0.0	0.0	0.1	0.2	0.4	0.1		0.1
223	+ Natural Background contribution	= LINE 2	4.0	0.0		0.0	0.5		1.6	1.0	1.0	0.0	0.0
224	2010-2011 projected Annual Result	44.90	18.6	2.1	1.2	1.0	1.3	1.1	4.8	9.2	2.7	0.0	3.0
225													

ANNUAL Average, based on CMB results for February to December 2000 plus the Jan 2001 Episode

SITEID	CONC	UCONC	PCMASS	Design Value	Sum of species	Burning		Motor Vehicle Mass		Tire/Brake Mass		Sulfate Mass		Nitrate Mass		Geological Mass		Geological Profile	Unassigned
BGS	57.7	3.6	98.5	57.0	55.6	6.3	2.3	3.6	2.4	1.1	1.2	3.0	0.3	14.9	1.3	26.7	5.8	FDKERANN	1.4
FSD	49.5	3.2	98.4	50.0	46.9	7.5	2.4	4.6	2.8	0.7	0.7	2.6	0.3	12.0	1.1	19.5	3.3	FDFSDANN	3.1
HAN	51.5	3.3	104.1	53.0	52.9	6.6	2.0	4.0	2.3	0.5	0.7	3.0	0.3	15.7	1.4	23.2	4.2	FDHANANN	0.1
VCS	52.5	3.3	99.6	54.0	51.8	6.7	2.5	4.0	2.5	0.5	1.0	3.1	0.3	15.9	1.5	21.7	3.8	FDVCSANN	2.2

This analysis provides a seasonally adjusted annual average, using the January episode to reflect the dominant winter chemistry.

Bakersfield Golden State Monthly

SITEID	DATE	CONC	UCONC	PCMAS	RSQ	CHISQ	Burning Mass	Burning Unc	Motor Vehicle Mass	Motor Vehicle Unc	Tire/Brake Mass	Tire/Brake Unc	Sulfate Mass	Sulfate Unc	Nitrate Mass	Nitrate Unc	Geological Mass	Geological Unc
BGS	1/1/01	205	10.3	93.6	1.0	0.9	23.3	6.3	6.7	4.7	1.3	1.7	7.0	0.7	95.4	7.8	58.2	9.6
BGS	Feb	24.4	1.9	96.4	1.0	0.7	4.1	2.3	1.7	1.3	0.6	0.6	1.2	0.1	5.1	0.6	10.9	3.2
BGS	Mar	22.2	2.1	107.7	1.0	1.0	2.1	2.2	2.1	1.4	0.6	0.6	1.9	0.2	5.5	0.6	11.7	3.1
BGS	Apr	31.5	2.4	107.8	1.0	0.4	6.3	3.2	2.1	1.7	0.5	0.7	3.0	0.3	4.9	0.6	17.3	4.6
BGS	May*	34.6	2.5	118.5	1.0	0.5	0.3	0.4	5.3	2.6			3.1	0.3	4.5	0.5	27.8	5.7
BGS	Jun*	41.3	2.7	102.7	1.0	0.6	0.9	0.4	5.1	2.6			3.8	0.3	3.1	0.4	29.4	6.0
BGS	Jul*	37.0	2.6	101.3	0.9	2.2	7.1	1.1	0.2	1.4	2.4	1.4	2.1	0.2	2.2	0.3	23.4	5.9
BGS	Aug*	43.5	2.6	97.8	1.0	1.2	4.1	0.8	2.2	1.9	0.5	1.4	2.5	0.3	2.9	0.4	30.2	6.5
BGS	Sep*	78.6	4.7	98.3	0.9	1.2	3.5	1.4	4.5	3.3	0.8	2.7	3.0	0.4	3.6	0.4	61.9	12.5
BGS	Oct*	36.1	2.8	83.9	1.0	1.0	3.5	0.7	1.6	1.3	1.4	1.0	1.9	0.2	5.2	0.6	16.7	4.3
BGS	Nov	48.4	2.9	86.3	1.0	0.4	7.9	3.4	4.6	2.7	0.6	0.7	2.2	0.2	14.0	1.2	12.3	3.1
BGS	Dec	90.2	5.1	87.4	1.0	0.6	12.5	5.1	7.0	4.2	2.1	1.2	4.3	0.4	32.2	2.7	20.9	5.4
Min		22.2	1.9	83.9	0.9	0.4	0.3	0.4	0.2	1.3	0.5	0.6	1.2	0.1	2.2	0.3	10.9	3.1
Avg		57.7	3.6	98.5	1.0	0.9	6.3	2.3	3.6	2.4	1.1	1.2	3.0	0.3	14.9	1.3	26.7	5.8
Max		205.0	10.3	118.5	1.0	2.2	23.3	6.3	7.0	4.7	2.4	2.7	7.0	0.7	95.4	7.8	61.9	12.5

Fresno Drummond Monthly

SITEID	DATE	CONC	UCONC	PCMAS	RSQ	CHISQ	Burning Mass	Burning Unc	Motor Vehicle Mass	Motor Vehicle Unc	Tire/Brake Mass	Tire/Brake Unc	Sulfate Mass	Sulfate Unc	Nitrate Mass	Nitrate Unc	Geological Mass	Geological Unc
FSD	1/1/01	186	9.4	87.9	1.0	1.1	40.1	11.3	18.5	9.6	2.5	1.5	5.0	0.7	62.4	5.1	35.1	6.8
FSD	Feb	27.0	2.1	97.3	1.0	0.7	5.7	2.5	3.1	1.8	0.3	0.4	1.1	0.2	7.7	0.8	8.3	2.1
FSD	Mar	23.9	2.1	116.0	1.0	0.7	4.6	2.4	3.1	1.8	0.1	0.4	1.8	0.2	8.2	0.9	9.9	2.3
FSD	Apr	24.8	2.2	112.1	1.0	0.6	3.4	2.7	2.4	1.6	0.2	0.5	2.4	0.2	5.0	0.5	14.4	3.0
FSD	May**	20.0	2.1	99.5	1.0	0.6	0.3446	0.32946	2.1	1.4			2.3269	0.22637	2.4774	0.32112	12.6	1.7055
FSD	Jun*	34.1	2.5	105.8	1.0	1.0	1.9	0.4	3.8	2.3	0.0	0.6	4.2	0.4	3.6	0.4	22.5	3.8
FSD	Jul*	26.4	2.3	100.6	1.0	0.6	1.0	0.4	1.5	1.3			1.7	0.2	2.7	0.3	19.6	2.2
FSD	Aug*	38.2	2.5	90.2	0.9	2.7	3.8	0.7	0.9	1.5	1.4	0.9	2.0	0.3	3.3	0.4	23.1	4.3
FSD	Sep*	56.7	3.3	92.8	1.0	0.9	1.5	0.6	3.4	2.5	0.9	1.0	2.6	0.4	3.6	0.4	40.6	6.0
FSD	Oct*	50.7	3.4	93.5	1.0	0.5	1.8	0.4	4.5	2.6			2.2	0.3	8.4	0.8	30.6	3.3
FSD	Nov	40.5	2.6	95.7	1.0	0.4	11.9	3.3	4.5	2.7	0.4	0.4	2.1	0.2	13.1	1.2	6.8	1.8
FSD	Dec	65.8	3.9	89.7	1.0	0.8	13.7	4.3	7.3	3.8	0.8	0.6	3.2	0.3	23.4	2.0	10.6	2.6
Min		20.0	2.1	87.9	0.9	0.4	0.3	0.3	0.9	1.3	0.0	0.4	1.1	0.2	2.5	0.3	6.8	1.7
Avg		49.5	3.2	98.4	1.0	0.9	7.5	2.4	4.6	2.8	0.7	0.7	2.6	0.3	12.0	1.1	19.5	3.3
Max		186.0	9.4	116.0	1.0	2.7	40.1	11.3	18.5	9.6	2.5	1.5	5.0	0.7	62.4	5.1	40.6	6.8

Hanford Monthly

SITEID	DATE	CONC	UCONC	PCMAS	RSQ	CHISQ	Burning Mass	Burning Unc	Motor Vehicle Mass	Motor Vehicle Unc	Tire/Brake Mass	Tire/Brake Unc	Sulfate Mass	Sulfate Unc	Nitrate Mass	Nitrate Unc	Geological Mass	Geological Unc
HAN	1/7/01	185	9.6	102.9	1.0	0.4	27.6	9.7	14.7	7.8	1.7	1.1	7.2	0.7	96.9	7.9	42.4	7.7
HAN	Feb	20.0	1.8	105.0	0.9	0.5	5.0	1.7	1.4	1.0	0.0	0.3	1.4	0.2	8.6	0.9	4.6	1.3
HAN	Mar	21.4	2.0	100.3	0.9	0.5	4.0	1.8	1.6	1.0	0.2	0.3	1.8	0.2	7.1	0.7	6.8	1.8
HAN	Apr*	22.3	2.1	120.6	1.0	0.3	0.4	0.3	3.2	1.6			2.2	0.2	5.0	0.5	16.1	2.8
HAN	May*	24.4	2.1	107.3	1.0	0.3	1.1673	0.35652	2.4	1.4			2.4472	0.22382	3.7747	0.44049	16.4	2.79498
HAN	Jun*	31.3	2.5	107.9	1.0	0.4	3.2	0.5	2.4	1.6	0.2	0.6	3.8	0.3	4.1	0.5	20.1	4.1
HAN	Jul*	38.7	2.6	107.9	0.9	0.7	3.6	0.6	2.7	1.6	0.2	0.7	3.4	0.3	5.6	0.6	26.3	4.7
HAN	Aug*	43.3	2.6	103.7	0.9	0.5	4.2	0.6	1.9	1.5	0.3	0.8	2.0	0.2	2.7	0.4	33.8	5.7
HAN	Sep*	70.5	4.0	105.3	0.9	0.5	2.5	0.8	4.3	2.7	0.5	1.2	3.1	0.4	5.0	0.7	58.8	8.8
HAN	Oct*	51.8	3.4	90.9	1.0	0.3	1.0	0.5	3.7	2.2	0.2	0.8	2.4	0.3	7.6	0.8	32.2	5.8
HAN	Nov	46.4	2.8	107.6	1.0	0.4	13.5	3.6	4.8	2.9	1.0	0.5	2.4	0.3	17.7	1.5	10.5	2.7
HAN	Dec	62.8	3.6	89.4	1.0	0.5	12.4	3.4	4.4	2.5	0.9	0.5	3.7	0.4	23.9	2.1	10.7	2.8
Min		20.0	1.8	89.4	0.9	0.3	0.4	0.3	1.4	1.0	0.0	0.3	1.4	0.2	2.7	0.4	4.6	1.3
Avg		51.5	3.3	104.1	1.0	0.4	6.6	2.0	4.0	2.3	0.5	0.7	3.0	0.3	15.7	1.4	23.2	4.2
Max		185.0	9.6	120.6	1.0	0.7	27.6	9.7	14.7	7.8	1.7	1.2	7.2	0.7	96.9	7.9	58.8	8.8

Visalia Church Street Monthly

SITEID	DATE	CONC	UCONC	PCMAS	RSQ	CHISQ	Burning Mass	Burning Unc	Motor Vehicle Mass	Motor Vehicle Unc	Tire/Brake Mass	Tire/Brake Unc	Sulfate Mass	Sulfate Unc	Nitrate Mass	Nitrate Unc	Geological Mass	Geological Unc
HAN	1/7/01	185	9.6	102.9	1.0	0.4	27.6	9.7	14.7	7.8	1.7	1.1	7.2	0.7	96.9	7.9	42.4	7.7
VCS	Feb	25.0	2.1	99.8	1.0	0.5	5.3	2.1	2.0	1.3	0.0	0.5	1.1	0.1	9.0	1.0	7.6	1.9
VCS	Mar	27.5	2.2	102.9	1.0	1.0	4.8	2.2	2.9	1.7	0.1	0.5	2.1	0.2	10.0	0.9	8.4	1.9
VCS	Apr	26.2	2.2	115.3	1.0	0.7	5.6	2.8	1.7	1.6	0.6	0.6	2.8	0.3	5.9	0.6	13.7	2.9
VCS	May**	29.1	2.3	112.8	1.0	0.7	5.4	3.6	1.4	1.6			2.8	0.3	3.8	0.5	19.4	3.2
VCS	Jun*	42.0	2.7	106.1	1.0	0.7	0.8	0.4	4.9	2.7			5.4	0.5	5.2	0.6	28.2	3.9
VCS	Jul*	34.7	2.5	107.8	0.9	1.4	3.7	0.6	1.8	1.7	0.5	1.1	2.9	0.3	4.9	0.6	23.7	3.8
VCS	Aug*	44.9	2.7	98.5	0.9	1.3	3.6	0.7	1.4	1.6	0.3	1.4	2.3	0.3	4.2	0.5	32.4	4.9
VCS	Sep*	59.1	3.5	84.4	0.9	1.3	3.4	0.8	1.9	1.9	0.7	1.6	3.0	0.3	4.8	0.6	36.0	5.7
VCS	Oct*	53.7	3.5	83.6	1.0	0.6	1.6	0.7	4.4	2.6	0.0	1.4	2.4	0.3	9.8	1.0	26.7	4.5
VCS	Nov	37.3	2.5	94.1	1.0	0.6	5.8	3.1	6.1	2.9			1.8	0.2	10.9	1.0	10.5	2.1
VCS	Dec	65.0	3.8	87.5	1.0	0.9	12.7	3.6	4.6	2.7	0.6	0.7	3.2	0.3	24.8	2.1	11.2	2.6
Min		25.0	2.1	83.6	0.9	0.4	0.8	0.4	1.4	1.3	0.0	0.5	1.1	0.1	3.8	0.5	7.6	1.9
Avg		52.5	3.3	99.6	1.0	0.9	6.7	2.5	4.0	2.5	0.5	1.0	3.1	0.3	15.9	1.5	21.7	3.8
Max		185.0	9.6	115.3	1.0	1.4	27.6	9.7	14.7	7.8	1.7	1.6	7.2	0.7	96.9	7.9	42.4	7.7

NOTES: Burning profile was switched from wood burning to agricultural burning based on ARB monthly emissions inventory estimates.
Asterisk * denotes AgBWheat profile used; ** denotes WBAlmond (some AgBWheat/WBAlmond used in April/May)

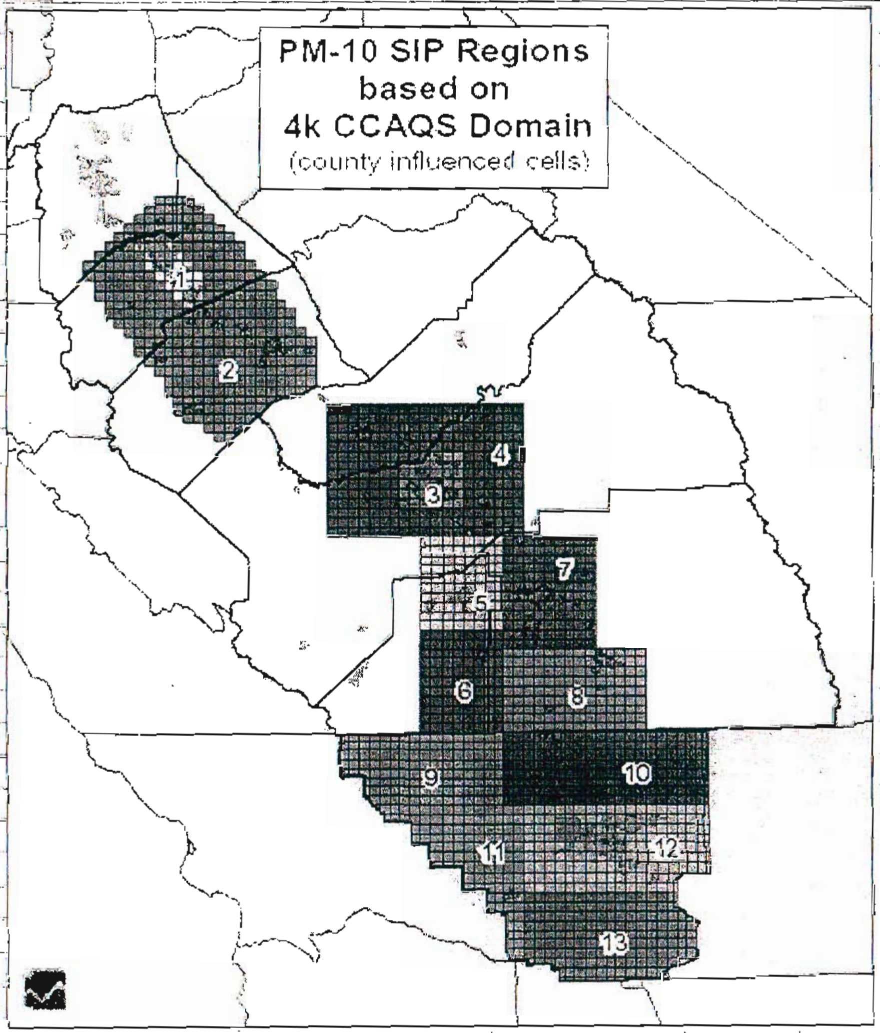
Source Profiles

	Jan-May and Nov-Dec	June-Oct	
Burning	22 WBOakEuc	27 AgBWheat*	
Sulfate	57 Amsul	57 Amsul	
Nitrate	60 Amnit	60 Amnit	
Motor Vehicle	65 CAMV	65 CAMV	
Tire/Brake	67 TireBrke	67 TireBrke	Note: (not used if run came out negative)
Geological	92 FDHANANN	92 FDHANANN	
	93 FDFREANN	93 FDFREANN	
	94 FDVCSANN	94 FDVCSANN	
	95 FDKERANN	95 FDKERANN	

AOI

		Rollback default percentage, adjust by episode properties					
			Local	PM2.5	Sub regional	Regional	Total
		Default 2.5-10	70	15	10	5	100
		Default 2.5	50	30	15	5	100
		Note: distribution of anthropogenic contribution after subtraction of background					
	Mapping of local, PM2.5-local,						
	and sub-regional based on						
	trajectory analysis		Areas used				
24-hr date	Site Name	Value	Local	PM2.5	Sub regional	Regional	# of dates
11/6/97	Corcoran-Patterson Avenue	199					
12/31/98	Bakersfield-Golden State Highway	159					
	Visalia-N Church Street	160					
1/12/99	Oildale-3311 Manor Street	156	12	12,13	Kern	SJV	1
10/21/99	Corcoran-Patterson Avenue	174	6	5,6,7,8	Kings-Tulare	SJV	2
	Fresno-Drummond Street	162	3	3,4	Fresno-Madera	SJV	3
	Turlock-S Minaret Street	157	1	1,2	Stanislaus-Merced	SJV	4
11/14/99	Bakersfield-Golden State Highway	183	12	6,7,8,10,12	Kings-Tulare-Kern	SJV	5
12/11/99	Hanford-S Irwin Street	183					
12/17/99	Corcoran-Patterson Avenue	174	6	6,8	Kings-Tulare	SJV	6
12/23/99	Fresno-Drummond Street	168	3	3,4,7	Fresno-Tulare	SJV	7
	Hanford-S Irwin Street	156	5	5,6,8	Kings-Tulare	SJV	8
1/1/01	Bakersfield-5558 California Avenue	186	12	9,10,11,12	Kern	SJV	9
	Bakersfield-Golden State Highway	205	12	9,10,11,12	Kern	SJV	10
	Clovis-N Villa Avenue	155	3	3,4	Fresno-Madera	SJV	11
	Fresno-1st Street	193	3	3,4	Fresno-Madera	SJV	12
	Fresno-Drummond Street	186	3	3,4	Fresno-Madera	SJV	13
	Oildale-3311 Manor Street	158	12	9,10,11,12	Kern	SJV	14
1/4/01	Bakersfield-5558 California Avenue	190	12	10,12,13	Kern	SJV	15
	Bakersfield-Golden State Highway	208	12	10,12,13	Kern	SJV	16
	Fresno-Drummond Street	159	3	3,4	Fresno-Madera	SJV	17
	Oildale-3311 Manor Street	195	12	10,12,13	Kern	SJV	18
1/7/01	Bakersfield-5558 California Avenue	159	12	10,12	Kern	SJV	19
	Bakersfield-Golden State Highway	174	12	10,12	Kern	SJV	20
	Corcoran-Patterson Avenue	165	6	6,8,10,12	Kings-Tulare-Kern	SJV	21
	Hanford-S Irwin Street	185	5	5,6,7,8,10	Kings-Tulare-Kern	SJV	22
	Modesto-14th Street	158	1	1,2	St-Me-Ma- Fr-Tu	SJV	23
11/9/01	Hanford-S Irwin Street	155	5	5,7,8	Kings-Tulare	SJV	24

			Areas used			
Annual	County	Value	Local	PM2.5	Sub regional	Regional
	Kern	57	12	Kern	Kern	SJV



APPENDIX E
Compliance Certification

ENERGY
INVESTORS
FUNDS

THREE CHARLES RIVER PLACE, 63 KENDRICK STREET • NEEDHAM, MASSACHUSETTS 02494
tel 781.292.7000 fax 781.292.7099 www.eifgroup.com

March 20, 2007

David Warner
Director of Permit Section
1990 East Gettysburg Avenue
San Joaquin Valley Air Pollution Control District
Central Region Office
Fresno, CA 93726-0244

Re: Project No. C-1062518 (Panoche Energy Center, LLC)
Energy Investors Funds - Certification of Compliance

Dear Mr. Warner,

Pursuant to SJVAPCD (District) Rule 2201 Section 4.15.2, *Compliance by Other Owned, Operated or Controlled Source*, EIF Management, LLC ("EIF") respectfully submits this *Letter of Certification* as it pertains to EIF's California "Major Source" facilities. EIF, as manager on behalf of its affiliated funds, owns, controls and/or operates two Major Source facilities in California, namely, Crockett Cogeneration and Burney Forest Power.

I hereby certify that Crockett Cogeneration and Burney Forest Power are in compliance or are on a schedule for compliance with all applicable emission limitations and standards. This certification shall speak as to the date of its execution. Should you have any questions in this regard, please call me at (781) 292-7008.

Respectfully,

W. Rick Carlson

W. Rick Carlson
Vice President, Investments

cc: Gary Chandler, Panoche Energy Center
Dave Jenkins, Panoche Energy Center
John Lague, URS Corporation

APPENDIX F
Health Risk Assessment and AAQA

(Revised)
San Joaquin Valley Air Pollution Control District
Risk Management Review

TO: Stanley Tom, AQE--Permit Services

FROM: Esteban Gutierrez, AQS--Technical Services

DATE: March 14, 2007

SUBJECT: Panoche Energy Center LLC

LOCATION: W Panoche Rd, Firebaugh, CA

APPLICATION #: C-7220-1-0 thru 6-0

PROJECT #: C-1062518

A. RMR SUMMARY

Categories	1-0 NG Turbine	2-0 NG Turbine	3-0 NG Turbine	4-0 NG Turbine
Prioritization Score	2.77	2.77	2.77	2.77
Acute Hazard Index	0.0	0.0	0.0	0.0
Chronic Hazard Index	0.0	0.0	0.0	0.0
Cancer Risk (10^{-6})	0.05	0.05	0.05	0.05
T-BACT Required?	No	No	No	No
Special Permit Conditions?	No	No	No	No

Categories	5-0 Diesel ICE	6-0 Cooling Tower	Project Totals	Facility toatal
Prioritization Score	NA	2.02	11.9	>1
Acute Hazard Index	NA	0.33	0.33	0.33
Chronic Hazard Index	NA	0.29	0.29	0.29
Cancer Risk (10^{-6})	0.32	0.0	0.52	0.52
T-BACT Required?	No	No		
Special Permit Conditions?	Yes	No		

Proposed Permit Conditions

To ensure that human health risks will not exceed District allowable levels, the following permit conditions must be included:

5-0 Diesel ICE

1. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102] N
2. The engine shall be operated only for maintenance, testing, and required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed **52** hours per year. [District NSR Rule and District Rule 4702] N

B. RMR REPORT

I. Project Description

Technical Services received a request on March 14, 2007 (Revised April 18, 2007), to perform a Risk Management Review and an AAQA for the proposed Installation of a new power plant. The facility will include the four Natural gas Turbines with ammonia slip, one 160 BHP Diesel fired Emergency ICE, and a Cooling tower.

II. Analysis

Toxic emissions for the four turbines were calculated using Ventura County's emission factors for external combustion sources. Ammonia emissions were supplied by the engineer, and the cooling tower emissions were derived from source test from the facility. In accordance with the District's *Risk Management Policy for Permitting New and Modified Sources* (APR 1905-1, March 2, 2001), risks from the proposed unit's toxic emissions were prioritized using the procedure in the 1990 CAPCOA Facility Prioritization Guidelines and incorporated in the District's HEARTs database. The prioritization score for these proposed units was greater than 1.0 (see RMR Summary Table). Therefore, a refined analysis was necessary.

The following parameters were used for the review:

POINT SOURCES:

Process	Stack Diameter (feet)	Exhaust Height (feet)	Gas Exit Flowrate (m/s)	Exhaust Temperature (°F)	Exhaust Direction
C-7220-1-0 thru 4-0	13.52	90.03	31.54	787	Vertical
C-7220-5-0	0.49	17	31.3	872	Vertical
C-7220-6-0*	22.01	39.01	6.098	100	Vertical

*The cooling tower has five cells each with identical parameters.

III. RMR Conclusion

The chronic and the acute risk were below one and the cancer risk for this project is less than one in a million. **Therefore, in accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risk will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for each proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

IV. AAQA

Technical Services also performed modeling for criteria pollutants CO, NOx, SOx, and PM_{10}; as well as the RMR. The emission rates used for criteria pollutant modeling were as follows

Pollutant/Unit	1-0		2-0		3-0	
	lb/hr*	lb/yr	lb/hr*	lb/yr	lb/hr*	lb/yr
NOx	187	48465	187	48465	187	48465
CO	309.75	92750	309.75	92750	309.75	92750
PM10	6.0	30,000	6.0	30,000	6.0	30,000
SOx	2.51	12,550	2.51	12,550	2.51	12,550

Pollutant/Unit	4-0		5-0		6-0	
	lb/hr*	lb/yr	lb/hr	lb/yr	lb/hr	lb/yr
NOx	187	48465	1.38	83	0	0
CO	309.75	92750	0.23	11	0	0
PM10	6.0	30,000	0.05	3	0.07	587.47
SOx	2.51	12,550	0.0	0.0	0	0

*Includes commissioning.

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*
Values are in $\mu g/m^3$

	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[1]	Pass[1]

*Results were taken from the attached PSD spreadsheets.
[1]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

V. AAQA Conclusion

The criteria modeling runs indicate the emissions from the proposed equipment will not cause or significantly contribute to a violation of a State or National AAQS. Therefore, no further modeling will be required and permitting may proceed as proposed.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

Attachments:

A. Individual Unit risk break down for future modeling
B. RMR Request from the Project Engineer
C. HARP Risk Results
D. Emissions Spreadsheets
E. AAQA/PSD Spreadsheets

All Values are in ug/m^3

	NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
TURB1	2.362E+01	3.156E-02	5.216E+01	2.372E+01	4.227E-01	2.299E-01	1.208E-01	1.090E-02	2.889E-01	2.586E-02
TURB2	2.547E+01	3.305E-02	5.625E+01	2.438E+01	4.558E-01	2.332E-01	1.238E-01	1.141E-02	2.959E-01	2.704E-02
TURB3	2.564E+01	3.322E-02	5.663E+01	2.440E+01	4.589E-01	2.306E-01	1.247E-01	1.147E-02	2.980E-01	2.698E-02
TURB4	2.336E+01	3.151E-02	5.160E+01	2.393E+01	4.181E-01	2.238E-01	1.236E-01	1.088E-02	2.956E-01	2.507E-02
CT1	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.600E-03	4.216E-03
CT2	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.571E-03	4.399E-03
CT3	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.542E-03	4.575E-03
CT4	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.514E-03	4.771E-03
CT5	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.485E-03	4.981E-03
FIRE	7.699E+00	4.478E-03	1.711E+00	5.081E-01	0.000E+00	0.000E+00	0.000E+00	0.000E+00	5.784E-02	2.573E-04
Background	1.722E+02	3.635E+01	5.709E+03	4.194E+03	5.062E+01	2.398E+01	7.990E+00	2.660E+00	1.080E+02	4.000E+01
Facility Totals	2.780E+02	3.648E+01	5.927E+03	4.291E+03	5.238E+01	2.490E+01	8.483E+00	2.705E+00	1.092E+02	4.013E+01
AAQS	470	100	23000	10000	655	1300	105	80	50	30
	Pass	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Fail**	**Fail**

EPA's Significatance Level (ug/m^3)

NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
0.0	1.0	2000.0	500.0	0.0	25.0	5.0	1.0	5.0	1.0

AAQA Emission (g/sec)

Device	NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
TURB1	2.36E+01	6.97E-01	3.90E+01	3.90E+01	3.16E-01	3.16E-01	3.16E-01	1.80E-01	7.56E-01	4.31E-01
FIRE	1.74E-01	1.19E-03	2.90E-02	2.90E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.30E-03	4.31E-05
TURB2	2.36E+01	6.97E-01	3.90E+01	3.90E+01	3.16E-01	3.16E-01	3.16E-01	1.80E-01	7.56E-01	4.31E-01
TURB3	2.36E+01	6.97E-01	3.90E+01	3.90E+01	3.16E-01	3.16E-01	3.16E-01	1.80E-01	7.56E-01	4.31E-01
TURB4	2.36E+01	6.97E-01	3.90E+01	3.90E+01	3.16E-01	3.16E-01	3.16E-01	1.80E-01	7.56E-01	4.31E-01
CT1	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.69E-03	1.69E-03
CT2	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.69E-03	1.69E-03
CT3	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.69E-03	1.69E-03
CT4	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.69E-03	1.69E-03
CT5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.69E-03	1.69E-03

APPENDIX G
California Energy Commission (CEC) Comments and District Responses

CEC COMMENTS / DISTRICT RESPONSES

CEC comments regarding the preliminary determination of compliance for Panoche Energy Center (District facility C-7220) are provided below followed by the District's responses.

1. CEC COMMENT – Hourly Emission Rates

The hourly emission rates provided by the project applicant appear to be internally inconsistent given that the Best Available Control Technology (BACT) emission levels are all based on ppmvd at 15 percent oxygen. This is particularly true with the Volatile Organic Compound (VOC) emission rates. Staff's calculations indicate the maximum hourly steady state emission rate for VOC at 2.0 ppmvd should be 2.23 lbs/hour, rather than 2.67 lbs/hour as given by the project applicant and PDOC. Staff's calculations are based on ideal gas law, where assuming all of the BACT levels are based on ppmvd at 15 percent oxygen the emissions can be calculated based on the (nitrogen oxides) NOx emission limit of 8.03 lb/hour. An example is as follows:

VOC lbs/hr = 8.03 NOx lb/hour x (2.0 ppmvd VOC BACT / 2.5 ppmvd NOx BACT) x (16 (VOC MW as methane) / 46 (NO_2 MW)) = 2.23 lbs/hour

Staff believes this internally consistent calculation leads to the correct BACT emission limit for VOC assuming that the NOx emission limit is correct to three digits as provided by the project applicant. We believe this emission rate provides internally consistent BACT emission rates and that this lower emission rate for VOC should be the BACT emission rate basis for the daily and quarterly emission limits.

DISTRICT RESPONSE

The applicant proposed emission factors are provided by the turbine manufacturer. The proposed emission factors will be verified upon source testing of the turbines. Therefore, the hourly emission limits provided by the turbine manufacturer will remain as the hourly emission limits for the PDOC.

2. CEC COMMENT – Quarterly Emission Limits

The PDOC conditions do provide operating hour limits by quarter, but do not provide quarterly emission limits. Due to the quarterly nature of offset requirements staff suggests that the FDOC contain quarterly emission limits in a permit condition, as was presented in the Starwood Power-Midway project PDOC.

DISTRICT RESPONSE

The PDOC conditions have an hourly emission limit and operating hours limits by quarter so a quarterly emission limit is implied and a direct quarterly emission limit is not required.

3. CEC COMMENT – Initial Commissioning Limitation

The project applicant has stipulated to minimizing initial commissioning impacts by only commissioning two turbines at a time. Staff recommends that the District memorialize this stipulation by adding a condition that limits the initial commissioning operation to no more than two turbines operating without a functioning Selective Catalytic Reduction (SCR) system and oxidation catalyst.

DISTRICT RESPONSE

The following condition will be added to the PDOC:

- No more than two of the turbines operating under C-7220-1, C-7220-2, C-7220-3 or C-7220-4 shall be commissioned at any one time. [District Rule 2201]

4. CEC COMMENT – Condition 12 Reference

Condition 12 should refer to Condition 28 rather than Condition 36.

DISTRICT RESPONSE

Revised per comment.

5. CEC COMMENT – Initial Commissioning Emission Limit for VOC

Staff believes that the emission rate for VOC given in Condition 14 should be consistent with the maximum hourly emission rate for VOC, which if shutdown emissions are not revised as recommended in another comment below, then the VOC emission limit in this condition should reflect the worst case shutdown emission rate of 17.14 lbs/hour.

DISTRICT RESPONSE

Revised per comment.

6. CEC COMMENT – Initial Commissioning Emissions Accrual Condition 18

Condition 18 of the PDOC should refer to Condition 37 rather than Condition 41. Additionally, staff believes that this condition should also state that the emissions from initial commissioning should also accrue against the quarterly emission limits (please also see staff's comment on page 1 of this letter recommending that quarterly emission limits be added as a PDOC condition.).

DISTRICT RESPONSE

Revised per comment.

7. CEC COMMENT – Emission Reduction Credit Certificates

Staffs' review of the SJVAPCD's website Emission Reduction Credit (ERC) lists, finds all of the listed ERCs necessary for the project except for S-2465-1, which is the only VOC ERC certificate for the project. Staff would appreciate the District providing an update on the status of this ERC certificate.

DISTRICT RESPONSE

ERC S-2465-1 is now currently S-2494-1 which still contains sufficient ERC amounts for the proposed project.

8. CEC COMMENT – Startup/Shutdown Emissions

Staff believes that the startup/shutdown emissions presented in the PDOC do not use a reasonable basis and do not reflect the emissions stipulated to by the project applicant in the AFC. The PDOC uses worst-case emissions determined based on one hour of operation in startup or shutdown mode. However, the project applicant has indicated that the startup and shutdowns should take 30 minutes and 10.5 minutes, respectively, with normal emissions the rest of an hour that has a startup or shutdown event (AFC p. 5.2-16). The project applicant, to staff's knowledge, has not specifically requested any other limitations on the startup or shutdown mode time or maximum emissions. Therefore, staff requests that either the FDOC reflect a revision of the startup/shutdown emission limits appropriate to the project applicant's specified unsteady state timeframes when in startup/shutdown mode. Alternatively, please provide the District's position on why the selection of the hour long startup and shutdown periods was made in the PDOC and why it will be retained in the FDOC. Any changes made to the PDOC's hourly startup/shutdown emissions made will need to be reflected as appropriate in the emission totals and the District DOC conditions, particularly Conditions 30 and 31.

DISTRICT RESPONSE

District Rule 2201 requires emission limits on a daily basis. The health risk assessment is performed based on an hourly emission limit. As long as the proposed turbines meet the hourly emission limit, compliance with District rules and regulations is satisfied. To provide the applicant with operational flexibility, only the hourly emissions are limited and not the number or duration of each startup and shutdown, except as required by Rule 4703.

9. CEC COMMENT – Startup/Shutdown Emission Limit Averaging Periods

Condition 30 allows a three hour averaging period for the startup emission rates. This is inconsistent with the duration of startup/shutdown event timeframes, as described in the comments directly above and below this comment. Staff believes this should be shortened to one hour averaging periods.

DISTRICT RESPONSE

Revised per comment.

10. CEC COMMENT – Startup/Shutdown Time Limits

PDOC Condition 33 limits startup/shutdown time to two hours per event. However, the startup event unsteady state operation is noted by the project applicant to be 30 minutes in duration and the shutdown unsteady state operation is noted to be 10.5 minutes in duration. Staff has not received any information from the project applicant requesting a startup/shutdown event time of two hours, or anything more than 30/10.5 minute event times that they provided in the AFC. Please either provide notation of the project applicant's request for this duration in the FDOC or reduce the duration limit in Condition 33 to value(s) more consistent with the project applicant's provided startup/shutdown timeframes. For comparison, the Pastoria expansion simple cycle 7F turbine was limited to startup/shutdown durations of one hour.

DISTRICT RESPONSE

District Rule 4703 allows startup and shutdown events of two hours. As long as the hourly emission limits are shown to be in compliance, the number and duration of startup and shutdown do not need to be limited, except as required by Rule 4703.

11. CEC COMMENT – Condition 35 PM10 Emission Limit

Staff believes that the PM10 daily emission limit contains a typographical error and should be 144.0, not 144.1 lbs/day (6.0 lbs/hour x 24 hours/day = 144.0 lbs/day).

DISTRICT RESPONSE

Revised per comment.

12. CEC COMMENT – Firewater Pump Engine Type and Emission Limits

Staff has reviewed the CARB/USEPA nonroad diesel engine emission standards, and the current standard for new engines between 100 and 175 horsepower would be the Tier 3 standard, rather than the Tier 2 standard identified in the PDOC for the firewater pump engine. Staff recommends that this engine be required to meet the Tier 3 standards.

DISTRICT RESPONSE

The applicant has agreed to install a Tier 3 engine if there is a CARB-approved engine at the time of installation. The ATCM allows a Tier 2 engine until three years after the date Tier 3 standards are applicable. The engine conditions have been revised to allow for an equivalent engine to be installed.

APPENDIX H
Air Resources Board (ARB) Comments and District Responses

ARB COMMENTS / DISTRICT RESPONSES

ARB comments regarding the preliminary determination of compliance for Panoche Energy Center (District facility C-7220) are provided below followed by the District's responses.

1. ARB COMMENT

Page 4 (Section VI) of the PDOC indicates that the combustion gases exit the turbines at 70 degrees F. This should probably read "700" degrees F.

DISTRICT RESPONSE

The temperature has been revised to read 700 degrees F.

2. ARB COMMENT

Page 22 (Section B.2) states that the SSPE2 is greater than the offset threshold for NOx only; however, the Offset Determination table indicates that the threshold is exceeded for PM10, CO and VOC as well.

DISTRICT RESPONSE

The evaluation has been revised to state the offset threshold is exceeded for NOx, PM10, CO, and VOC.

3. ARB COMMENT

Page 24, PM10 offset calculation indicates a 345 lb/year contribution from the emergency fire pump; however, on Page 13, the annual PM10 emissions from the fire pump are identified to be 3 lb/year.

DISTRICT RESPONSE

The 345 lb/year value has been revised to 3 lb/year.

4. ARB COMMENT

Page 2 of Appendix D states that the fire pump engine may be operated up to 100 hours/year for testing and maintenance. This PDOC limits the engine to 52 hours/year for testing and maintenance.

DISTRICT RESPONSE

Page 2 of Appendix D has been revised to read 52 hours/year for testing and maintenance.

5. ARB COMMENT

On page 40 of the PDOC, it is stated that, "to ensure this source is not a major air toxics source," a permit condition requiring initial and annual source testing will be included. Annual emission limits should be included as a permit condition.

DISTRICT RESPONSE

The following condition will be added to the PDOC:

- Hazardous Air Pollutant (HAP) emissions shall not exceed 25 tpy all HAPS or 10 tpy any single HAP. [District Rule 4002]

6. ARB COMMENT

Page 61 of the PDOC indicates a District requirement (Rule 4703, Section 6.4) that the Higher Heating Value and Lower Heating Value of gaseous fuels be determined using ASTM D3588-91, ASTM 1826-88, or ASTN 1945-81; however, in the subsequent proposed permit condition, this requirement is not included.

DISTRICT RESPONSE

The following condition will be added to the PDOC:

- HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a),(b) and District Rule 4703, 6.4.5]

7. ARB COMMENT

Pg 71 of the PDOC (CHSC 42301.6) states that the facility is located within 1,000 feet of a school. It is our understanding that the facility is not located within 1,000 feet of a school.

DISTRICT RESPONSE

Page 71 has been revised to state the facility is not within 1,000 feet of a school.

8. ARB COMMENT

Condition 6, acid rain permit application submittal requirement does not include a date by which the application must be submitted.

DISTRICT RESPONSE

Condition 6 has been revised to read the following:

- Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

9. ARB COMMENT

Condition 21 requires that the permittee submit information correlating the NOx control system operating parameters to measured NOx output. The deadline for providing this information is not included. Additionally, there is no requirement to repeat this correlation on a regular (annual?) basis.

DISTRICT RESPONSE

Rule 4703 does not require the parametric relationship to be demonstrated on an on-going basis. Therefore, no action will be taken to include an annual correlation requirement.

Condition 21 has been revised to read the following:

- The owner or operator shall submit to the District, before issuance of the Permit to Operate, information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when no continuous emission monitoring data for NOx is available or when the continuous emission monitoring system is not operating properly. [District Rule 4703]

10. ARB COMMENT

On page 9 of the PDOC, turbine shutdown emissions are identified as 0.3 lb/hour for SOX; however permit condition 31 sets a shutdown limit of 2.51 lb/hour.

DISTRICT RESPONSE

The shutdown SOx emission limit has been revised to 2.51 lb/hour on page 9.

11. ARB COMMENT

In condition 33, startups should be limited to 30 min. (not 2 hrs) & shutdowns to 10.5 min (not 2 hrs) as that is what the emissions are based on. Additionally, the permittee should be limited to 3 startups and shutdowns/day & 365 startups and shutdowns/year.

DISTRICT RESPONSE

The District limits hourly emissions for startup and shutdown and total daily emissions and not the number of hours or events. As long as the hourly limits and total daily and annual emission limits are met, there is no need to limit the number of startups and shutdowns on a daily or annual basis.

12. ARB COMMENT

There are no daily or annual emission limits for NH3.

<u>DISTRICT RESPONSE</u>

There is an hourly NH3 limit which implies a daily emission limit assuming 24 hours per day operation (see condition 29). There is also a hour limit for each quarter which implies an annual emission limit (see condition 36). Therefore, no direct daily or annual emission limit for NH3 is required.

13. ARB COMMENT

There should be a record keeping requirement associated with the PM10 daily emission limit.

<u>DISTRICT RESPONSE</u>

The following condition will be added to the PDOC:

- The permittee shall maintain records of the calculated PM10 emission rate and the laboratory water sample analysis. [District Rule 1070]

14. ARB COMMENT

There should be a District notification and recordkeeping requirement associated with the water sample analysis required in condition 10.

<u>DISTRICT RESPONSE</u>

The following condition will be added to the PDOC:

- The permittee shall maintain records of the calculated PM10 emission rate and the laboratory water sample analysis. [District Rule 1070]

APPENDIX I
Panoche Energy Center Comments and District Responses

PANOCHE COMMENTS / DISTRICT RESPONSES

Panoche comments regarding the preliminary determination of compliance for Panoche Energy Center (District facility C-7220) are provided below followed by the District's responses.

1. PANOCHE COMMENT

Page 4: Section VI, first paragraph. The combustion gases exit the turbine at approximately 800F, not 70F as listed.

DISTRICT RESPONSE

The temperature has been changed to 700F.

2. PANOCHE COMMENT

Page 7: Section B. Lists the sulfur "emissions" as 1.0 gr-S/100 scf. This value is the sulfur content of the fuel gas, not the exhaust emissions. The listed value is not applicable to an emission statement. It should read "**2.51 lb/hr of SOx**."

DISTRICT RESPONSE

Revised to read the following: 2.51 lb/hr SOx (based on 1.0 gr-S/100 scf).

3. PANOCHE COMMENT

Page 8: First paragraph. PEC suggests that the sentence should read "...estimated by the manufacturer for **each of** the proposed CTGs..."

DISTRICT RESPONSE

Revised per comment to read "...per manufacturer's estimate for each of the proposed CTGs...".

4. PANOCHE COMMENT

Page 8: First table "Normal Emission Rates and Concentrations". SOx emission limit concentration is listed as 1.0 grS/100 scf. As noted in #2 above, this value refers to the fuel, and cannot be used as a concentration limit of the exhaust gas.

DISTRICT RESPONSE

Reference to 1.0 gr-S/100 scf has been removed from the table.

5. PANOCHE COMMENT

Page 8: Second, third, and fourth tables. The Startup Emissions, Warmup Emissions, and Total Startup Emissions include values that are not included in the original "Determination of Compliance Conditions." PEC is concerned that these emission rates are not guaranteed from the vendor, nor are they verifiable with the CEM system, because the CEM system is designed to "complete a minimum of one cycle of operation ... for each 15-minute period..." Therefore, emissions during a 10 minute startup will not be officially reported. However, if this is included with the "Worst Case Startup Emissions" listed in the fifth table, then it should not be a problem.

DISTRICT RESPONSE

Emissions are included in the "Worst Case Startup Emissions" table. No change is required.

6. PANOCHE COMMENT

Page 9: First table. Same issue with Shutdown Emissions as described in #5 above.

DISTRICT RESPONSE

See response #5.

7. PANOCHE COMMENT

Page 14, section VIII, Rule 1080 discussion, second sentence of first paragraph: Please change text to make clear that there will be one stack and one CEM's for each pair of CTG's.

DISTRICT RESPONSE

Additional language has been added to the Rule 1080 discussion in accordance with your comment.

8. PANOCHE COMMENT

Page 10: Section C.2.a. Second sentence incorrectly refers to "both turbines". The last two sentences should read: "The maximum hourly PE for **each** turbine is when **it** is starting up. The maximum hourly emissions for **each** turbine are summarized in the table below:"

DISTRICT RESPONSE

Revised per comment.

9. PANOCHE COMMENT

Page 11: Section b, second sentence. Sentence should read "The results **for each turbine** are summarized ..."

DISTRICT RESPONSE

Revised per comment.

10. PANOCHE COMMENT

Page 12: Section d. Sentence should read "The hourly, daily, and annual PE2 **for each turbine is** summarized ..."

DISTRICT RESPONSE

Revised per comment.

11. PANOCHE COMMENT

Page 21: Section 3. States that BACT has been satisfied with the following: SOx and PM10 with "gas with <0.75 grains S/100 scf". PEC believes this value should be **1.0** grains S/100 scf to be consistent with Condition 27 of "Determination of Compliance Conditions".

DISTRICT RESPONSE

The < 0.75 gr-S/100 scf requirement is only for units fired on non-PUC-regulated natural gas. Since the proposed turbines are fired on PUC-regulated natural gas, this requirement is not applicable. No change is required.

12. PANOCHE COMMENT

Page 49: Section 60.4400 - NOx Performance Testing, second paragraph. Replace "fourth" with "**forth**".

DISTRICT RESPONSE

Revised per comment.

13. PANOCHE COMMENT

Page 51: Rule 4101 Visible Emissions, first sentence. PEC suggests inclusion of the word "cause" as follows: "...no person shall **cause** discharge into the atmosphere..."

DISTRICT RESPONSE

Rule 4101 Section 5.0 wording does not include the word "cause". Therefore, no change is required.

14. PANOCHE COMMENT

Page 53: Rule 4201 Particulate Matter Concentration, first equation and following description of input values. Two issues:

a. The equation uses "air flow rate" in the denominator, then uses an input value of "Exhaust Gas Flow". Since the turbine technically has both air flow and exhaust gas that are different values, PEC believes the equation should be clarified to more correctly reflect the use of Exhaust Gas Flow.

b. The equation incorrectly uses a value of 888,554 scfm. This is an incorrect use of this value. The GE Performance Data Case 104 predicts 888,554 acfm, but the equation requires scfm, so 361,394 scfm is correct if this same test case is used. This changes the PM Concentration calculations on Page 54 to 0.0019 gr/scf.

DISTRICT RESPONSE

a. Revised per comment. b. Revised per comment.

15. PANOCHE COMMENT

Page 54: Second line. Results of changes to equation on Page 53 (See #14.b above) changes results to 0.0019 gr/scf.

DISTRICT RESPONSE

Revised per comment.

16. PANOCHE COMMENT

Page 54: C-7220-6-0. Same concern as #14.a - the use of "air flow rate" and "exhaust gas flow" are used interchangeably, but should not be. PEC is unable to determine if the value used as the Exhaust Gas Flow is correct.

DISTRICT RESPONSE

Revised per comment.

17. PANOCHE COMMENT

Page 56: Rule 4703 Stationary Gas Turbines, first sentence. Incorrectly identifies the project as installing "three 180 MW gas turbines". Should be modified to "four 100 MW gas turbines".

DISTRICT RESPONSE

Revised per comment.

18. PANOCHE COMMENT

Page 57: Calculations on top half of page. PEC was unable to find the source of 3,412 Btu/kW-hr and 7,815 Btu/kW-hr. These values are not included in the GE data, but they could be some sort of default value included in the calculation. PEC is concerned that they could be carried over from the 180 MW turbines incorrectly referenced in the previous paragraph.

DISTRICT RESPONSE

The value of 3412 Btu/kW-hr was taken from Rule 4703 Section 5.1.1. The value of 7815 Btu/kW-hr was taken from page 3-9 of the submitted application. No change is required.

19. PANOCHE COMMENT

Page A-11. Remove the words "Power Plant" from the first sentence to read as follows: "The owner/operator of the Panoche Energy Center (PEC) ..."

DISTRICT RESPONSE

Revised per comment.

20. PANOCHE COMMENT

Page A-12. In Condition #15, references to Conditions 12 and 14 should be reversed to read as follows: "During the commissioning period, the permittee shall demonstrate NOx and CO compliance with condition #14 through the use of properly operated and maintained continuous emissions monitors and recorders as specified in condition #12.

DISTRICT RESPONSE

Revised per comment.

21. PANOCHE COMMENT

Page A-13. For Condition #21, PEC suggests that the original language be replaced with the following: "The owner or operator shall submit to the District, before issuance of the Permit to Operate, information correlating the control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when no continuous emission monitoring data for NOx is available or when the continuous emission monitoring system is not operating properly. [District Rule 4703]"

DISTRICT RESPONSE

Revised per comment.